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U.S. DEPARTMENT OF ENERGY

# FIRST ANNUAL CLEAN COAL TECHNOLOGY CONFERENCE

# PROCEEDINGS

CLEAN COAL TECHNOLOGY

September 22-24, 1992
Cleveland, Ohio

November 1992

**PURPOSE:**

The first public review of the U.S.DOE/Industry co-funded program to demonstrate the commercial readiness of Clean Coal Technologies (CCT).

**OBJECTIVES:**

Provide electric utilities, independent power producers, and potential foreign users information on the DOE-supported CCT projects including status, results, and technology performance potential;

To further understanding of the institutional, financial, and technical considerations in applying CCTs to Clean Air Act compliance strategies;

To discuss the export market, financial and institutional assistance, and the roles of government and industry in pursuing exports of CCTs; and

To facilitate meetings between domestic and international attendees to maximize export opportunities.

**DATE:**

September 22-24, 1992

**LOCATION:**

Sheraton Cleveland City Centre Hotel
777 St. Clair Avenue
Cleveland, Ohio 44114
(216) 771-7600 or (800) 321-1090

**TARGETED AUDIENCE:**

The intended audience are technical and policy planning representatives (both domestic and foreign) for the following: technology users, utilities and independent power producers, vendors, equipment manufacturers, state and federal legislative and regulatory bodies, environmental organizations, etc.

**FORMAT:**

The format for the meeting will be the following: an open plenary session followed by regulatory, utility and export panel sessions. The remainder of the meeting will be comprised of technical paper presentations by the CCT Program project sponsors.

# U.S. DEPARTMENT OF ENERGY

# FIRST ANNUAL
# CLEAN COAL TECHNOLOGY CONFERENCE

# PROCEEDINGS

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*Opening Greeting:*
**Donald E. Jakeway**, Director, Ohio Department of Development

*State Regulatory View of Compliance Strategies:*
**The Honorable Craig A. Glazer**, Chairman, Public Utilities Commission of Ohio

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**Gary L. Neale**, President and Chief Operating Officer, Northern Indiana Public Service Company

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**Thomas Altmeyer,** Senior Vice President, Government Affairs, National Coal Association

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**Robert D. Brenner,** Director, Air Policy Office, U.S. Environmental Protection Agency

# BIOGRAPHIES OF KEYNOTE SPEAKERS

**James G. Randolph**
Mr. Randolph was nominated by the President on November 1, 1991, to be Assistant Secretary of Energy for Fossil Energy, U.S. Department of Energy (DOE). He was confirmed by the U.S. Senate on November 13, 1991, and sworn into office on November 25, 1991. The Assistant Secretary for Fossil Energy provides the leadership and management direction for DOE's fossil energy programs to meet National Energy Strategy objectives. These include the Clean Coal Technology Program, Strategic Petroleum Reserves, Naval petroleum Reserves and an extensive national research and development effort to develop and demonstrate coal, shale, oil and natural gas technologies.

**Jack S. Siegel**
Jack S. Siegel was named Deputy Assistant Secretary for Coal Technology, Office of Fossil Energy, U.S. Department of Energy (DOE) in June 1986. In this position he is responsible for managing the $5 billion dollar industry/DOE clean coal technology demonstration program and DOE's research and development on a wide variety of coal-based precombustion, combustion, post-combustion and conversion technologies to enable coal to be used more economically, more efficiently and more cleanly. Mr. Siegel is also the Chairman of the International Energy Agency's Working Party on Fossil Fuels which is responsible for the conduct of research and the development of policy options for the member countries of the International Energy Agency. Previously, Mr. Siegel served as Deputy Director for Coal Utilization, Advanced Conversion and Gasification, Office of Fossil Energy. He was responsible for guiding the research and development in emerging coal technologies in the areas of fluidized bed combustion, coal preparation, gas cleanup, coal gasification, fuel cells, heat engines and magnetohydrodynamics.

**Donald E. Jakeway**
Mr. Jakeway, Director of the Ohio Department of Development, holds one of the most critical positions in state government—devising a new economic development strategy to insure Ohio's competitiveness in national and international marketplaces. Development Director Jakeway is responsible for promoting and planning programs to assure economic growth; create and retain Ohio jobs; and provide technical assistance to various other state departments, local governments and public-private organizations. The Director is also responsible for programs that assist existing Ohio businesses remain competitive in the global market, including expansion of export opportunities and development of new markets world-wide for Ohio firms. He also encourages expansion of minority business enterprises.

**Craig A. Glazer**
On February 20, 1991, Governor George V. Voinovich appointed Mr. Glazer as Chairman of the Public Utilities Commission of Ohio commencing on April 11, 1991. Mr. Glazer presently serves as a member of the Executive Committee of the Great Lakes Conference of Utility Commissioners and is a member of the Energy Conservation Committee of the National Association of Regulatory Utility Commissioners. Mr. Glazer has practiced extensively before state and federal regulatory agencies including FERC, FCC and Judge Greene in the AT&T post-divestiture review and was responsible for some of the major precedents in Ohio public utility law including *Public Utilities Fortnightly*'s "Case of the Year".

*Biographies of Keynote Speakers (continued)*

**Girard F. Anderson**
Mr. Anderson was elected president and chief operating officer of Tampa Electric in July, 1987. He took office November 1. In October, 1987, TECO Energy, Inc.'s board of directors named Mr. Anderson to the additional post of executive vice president—Utility Operations of TECO Energy, Inc. In 1980, Mr. Anderson was elected vice president of production operations and maintenance before being promoted to senior vice president of power distribution in April, 1985. In that position, he had responsibility for Customer services, system engineering, and transmission and distribution operations.

**Gary L. Neale**
In addition to being the President and Chief Operating Officer of the Northern Indiana Public Service Company, Mr. Neale serves on the Board of Directors of the American Gas Association, as well as their Government Relations Committee. He is also on the boards of the Indiana Gas Association, the Indiana Electric Association, and the Indiana Chamber of Commerce. He has been appointed by the governor of Indiana to the Economic Development Council, to the Energy Policy Forum, and to the Clean Air Advisory Committee. He is a member of the Economic Club of Chicago. He is also on the boards of directors of Modine Manufacturing Company, Racine, Wisconsin; Gainer Bank, Merrillville, Indiana; and the Northwest Indiana Symphony Orchestra.

**Thomas Altmeyer**
Thomas Altmeyer is Senior Vice President for Government Affairs with the National Coal Association. Tom works on all issues impacting the production, transportation and use of coal on a daily basis. Previously he was Vice President for Government Affairs with the Mining and Reclamation Council of America, as well as Counsel to the U.S. Senate Labor and Human Resources Committee, and Principal Energy Counsel to former Senator Jennings Randolph from West Virginia.

**Robert D. Brenner**
Robert Brenner plays a key role in the development and review of air regulations and policies, especially those relating to implementation of the Clean Air Act. In addition, he serves on the Agency's Steering Committee, which manages the development of all EPA regulations. He was also staff director of the Agency's effort to reauthorize the Clean Air Act and was senior policy analyst on electric utility issues.

# KEYNOTE ADDRESS

**JAMES G. RANDOLPH**
**ASSISTANT SECRETARY FOR FOSSIL ENERGY**
**U.S. DEPARTMENT OF ENERGY**

**FIRST ANNUAL**
**CLEAN COAL TECHNOLOGY CONFERENCE**
**CLEVELAND, OHIO**
**SEPTEMBER 22-24, 1992**

I would like to welcome everyone to this exciting event. This conference marks the transition of the Clean Coal Technology (CCT) Program from a concept, surrounded by skepticism that Government and industry could work together, to a successful partnership that is addressing some of the Nation's most significant energy and environmental issues. Projects now underway through joint sponsorship are producing data that will:

- demonstrate that coal can be used for energy while meeting even the most stringent of environmental requirements and

- establish the feasibility of a number of power production and/or pollution control options that can be used by utilities to produce power more efficiently while meeting the requirements of load growth and the demands of the environment.

The Program was initiated more than 5 years ago in an attempt to resolve a transboundary pollution problem and to develop low cost alternatives to conventional scrubbers in anticipation of acid rain legislation. That very focused objective is clearly being met. At this conference you have heard, and will continue to hear today, about technologies like in-duct sorbent injection, limestone injection multi-stage burners, LIFAC, Confined Zone Dispersion and other low capital cost, moderate $SO_2$ removal efficiency technologies which address this objective.

The Program subsequently has grown to include a number of additional objectives. These include:

- advanced options for the control of $NO_x$. These options such as low $NO_x$ burners, selective catalytic reduction processes, combined $SO_2/NO_x$ removal systems, etc., recognize and seek to reduce the impact of $NO_x$ in ozone depletion, acid rain, visibility impairment and global climate change,

- niche markets important to the coal industry. Examples of such projects include coal upgrading processes, direct steel making, cement kiln cleanup techniques, etc., and,

- perhaps, most importantly, the CCT program addresses the clean and efficient production of electric power, the mainstay of the coal industry. Today, 55% of electricity is coal-based and 85% of the coal produced is for utilities. The National Energy Strategy states that between 1990 and 2000 power generation growth will be fueled primarily by natural gas, up from 12% of market today to 20% in 2000. After 2000, however, natural gas prices will rise relative to coal and utilities will need more baseload capacity. Thus, coal's utility market share, which is projected to decline to 49% in 2000 is expected to rebound to rebound to 56% in 2010.

  As a result, new ways of using coal to address today's perceptions and environmental concerns are required. The CCT program is addressing these concerns by demonstrating technologies like circulating fluidized-bed combustion - both atmospheric and pressurized - pressurized fluidized-bed combustion, advanced integrated gasification combined cycle, and control technologies for ultra-high efficiency removal of $SO_2$, and $NO_x$. In addition, with the opportunities of Round 5, and the promise that additional power generation concepts are nearing graduation from our R&D programs, even more efficient and cleaner coal-based options are on the horizon.

The CCT Program now contains 41 projects in 22 States, that will utilize the full range of U.S. coal. Ten major types of technologies are being demonstrated that include utility power and pollution control systems, technologies that address environmental problems at cement plants and steel mills, and transportation applications for coal. As a result, the program is developing the technologies that will allow coal to not only maintain its current domestic markets, but expand into new markets as well.

As important as the U.S. market is for CCTs, we now recognize that there are other opportunities we did not even consider back in 1986 when the program was conceived. The potential worldwide market for CCTs pales the U.S. market, offering export opportunities that can create U.S. jobs, and strengthen the U.S. economy while addressing energy and environmental needs of the international community.

The Department has been working in Poland and Czechoslovakia with the U.S. Agency for International Development on several projects which you may have heard about. Eastern Europe and the former Soviet republics are coal-based economies. However, past practices used in producing coal and converting it to useful energy forms has resulted in environmental problems and energy concerns. This region appears well suited for innovative coal preparation and low cost retrofit technologies.

Also, the Department recently led a CCT trade mission to Indonesia and Thailand. Thailand will be constructing between 1,000-1,500 MW of coal-fired electric utility capacity per year and Indonesia about 2,500 MW per year for the next 15 years. A great deal of interest in CCTs and U.S. led projects was found to exist. The opportunities in these 2 countries, however, represent the tip of the iceberg in Asia. The Energy Information Agency's projections for coal use in electric power generation demonstrate large potential markets for CCTs. In China alone, electric power coal consumption, which is over 300 million tons per year today, is expected to rise by over 50% by 2010 to around 500 million tons. Electric utility coal use in developing and developed Pacific Rim nations is expected to grow by 70% over the same time period to about 115 million tons.

Even here in North America, opportunities for CCT exports exist. In Mexico, coal consumption is estimated to exceed 12 million short tons in 2010 of which approximately 6 million short tons will be used in the electric power generation sector.

I recognize that the more advanced processes, like some of those in the CCT demonstration program, and those in the R&D pipeline, will not be deployed today in these countries. Instead, there will be a transition to more modest performance technologies which nonetheless represent great improvements over the technologies currently used in many of these countries. As the more advanced CCTs are proven and environmental requirements are tightened, they too will be used. The U.S. should be in a position to take advantage of these opportunities. We are the world's leader in coal-based power systems, both conventional and advanced systems. U.S. industry has a worldwide reputation for economic, efficient and reliable energy systems. If we capitalize on our reputation and add to it with proven demonstration units, major new markets can be created for U.S. vendors.

The Department has just completed a study looking at potential export opportunities for CCTs. The study concludes, using conservative estimates, that between now and 2010:

- worldwide growth in coal consumption should increase by almost 800 million short tons from today's 4.3 billion;
- of this, almost 250 million short tons in coal growth for electric power production is projected;
- worldwide market for CCTs, just to meet the electric power and industrial steam needs, will exceed $400 billion of which about $110 billion is likely to be provided through exports of CCT goods and services;
- a $110 billion export market would result in over 80,000 new jobs; and
- in addition to these economic opportunities, the use of CCTs in these countries would lead to improvements in the global environment.

Why am I emphasizing the export opportunities of CCTs available to you, a primarily electric utility audience? Because the largest part of these new markets for CCTs internationally will be for utility applications. It is you in the utility industry who must play a key role in the export initiative. The U.S. is viewed of having the most efficient and reliable electrical generation and distribution system in the world. The world sees U.S. electric utilities as the most advanced in terms of their ability to analyze options and to develop and implement generation plans under a variety of conditions. As a result, U.S. utility involvement in a foreign project would bring credibility and a sense of reality to that project. I view your role then as that of the project team's quarterback. A successful U.S. project team will need an A&E firm, an equipment vendor, host country participants, and a U.S. utility who can orchestrate the project much as you do here in the U.S.

I recognize that some of you are already moving in these directions through IPP subsidiaries and on your own. I am also aware that the Public Utility Company Holding Act may inhibit utility involvement in some cases. But, the market is so large and the U.S. job implications and trade potential are so great that we must move aggressively as a team to capture these opportunities.

U.S. Government assistance is available. The U.S. Agency for International Development, the Trade and Development Program, the Overseas Private Investment Corporation, Export-Import Bank of the U.S., the U.S. Department of Commerce and the U.S. Department of Energy, among others have organized their export assistance efforts on CCTs into a CCT Subgroup under the U.S. Department of Commerce's Trade Promotion Coordinating Committee. If you attended yesterday's Government Export Panel Session, you learned about the activities of these agencies and the coordination of their effort.

We have certainly come a long way since the inception of the CCT Program. We now have many projects in operation throughout the U.S. that will be the basis for commercial deployment, both domestically and internationally. We are clearly now the world leaders in clean coal technology. We are viewed as a good international partner, and U.S. Government efforts to support CCT exports are now coordinated among U.S. Government agencies and with industry.

With these ingredients, we should be able to resolve the environmental issues associated with coal in the United States, as well as win a major international market for coal and clean coal technologies abroad.

Each of you has played a part in that success, and I appreciate the effort you made to be here today.

**COMMENTS OF**
**DONALD E. JAKEWAY, DIRECTOR**
**OHIO DEPARTMENT OF DEVELOPMENT**
**SEPTEMBER 23, 1992**
**USDOE CONFERENCE/CLEVELAND, OHIO**

- WELCOME TO OHIO. WE ARE THRILLED THAT OHIO IS HOST TO THE US DEPARTMENT OF ENERGY'S FIRST ANNUAL CLEAN COAL TECHNOLOGY CONFERENCE.

- AS MANY OF YOU KNOW, OHIO IS A MAJOR USER AND PRODUCER OF COAL IN THE UNITED STATES.

- OHIO KNEW IN THE 1980'S THAT NOT ONLY OUR COAL AND ELECTRIC UTILITY INDUSTRIES, BUT THE ECONOMY WOULD BE AFFECTED BY THEN-PENDING ENVIRONMENTAL LEGISLATION. FOR THAT REASON, OHIO CREATED ITS OWN CLEAN COAL TECHNOLOGY PROGRAM, WHICH IS NOW ONE OF THE LEADING PROGRAMS OF ITS TYPE IN THE UNITED STATES. OHIO'S PROGRAM, WHICH HAS SUPPORTED OVER 80 PROJECTS AND ALLOCATED APPROXIMATELY $84 MILLION, IS ADMINSITERED BY MY DEPARTMENT'S OHIO COAL DEVELOPMENT OFFICE, AND IS STRONGLY SUPPORTED BY GOVERNOR GEORGE VOINOVICH.

- HE IS KEENLY AWARE OF THE IMPACTS TO OUR UTILITIES, OUR INDUSTRIES, AND OTHER SECTORS AND REGIONS OF OUR ECONOMY WHICH USE OR ARE DEPENDENT UPON OHIO COAL. HE IS SUPPORTIVE OF TECHNOLOGY DEVELOPMENT IN GENERAL, AND HAS A PARTICULAR INTEREST IN SEEING THE PROMISE OF CLEAN COAL TECHNOLOGIES PROVEN. YOU HAVE A VERY IMPORTANT TASK.

- OHIO, AS ARE MANY OF YOU, IS ON THE CUTTING EDGE FOR CLEAN COAL TECHNOLOGY RESEARCH AND DEVELOPMENT. THAT IS DUE IN PART TO OUR STAFF. I'M SURE MANY OF YOU KNOW JACKIE BIRD, THE DIRECTOR OF THE OHIO COAL DEVELOPMENT OFFICE, AND HOWARD JOHNSON AND RICHARD CHU WHO ARE ALSO PART OF OUR

COAL TEAM. DON SCOTT IS ALSO HERE TODAY, AND HE HEADS DEVELOPMENT OF ALL OTHER TECHNOLOGY DEVELOPMENT FOR THE STATE.

- THE CLEAN COAL TECHNOLOGY PROGRAM IS ONE OF THE BEST EXAMPLES I HAVE EVER SEEN OF THE "PUBLIC/PRIVATE PARTNERSHIPS" SO OFTEN ENCOURAGED. NO ONE ORGANIZATION COULD PURSUE THESE PROJECTS ALONE, NOT THE FEDERAL GOVERNMENT, STATE GOVERNMENTS, UTILITIES OR PRIVATE DEVELOPERS. BUT LOOK AT WHAT WE ARE ACCOMPLISHING TOGETHER!

- ALONG THAT LINE I'D LIKE TO TAKE THIS OPPORTUNITY TO URGE YOU TO TAKE ADVANTAGE OF USDOE'S ROUND 5 SOLICITATION. IT IS MY HOPE THAT MANY OF YOU IN ATTENDANCE HERE TODAY WILL SUBMIT PROJECT PROPOSALS BY DECEMBER 7TH FOR COST-SHARED FUNDING UNDER THIS PROGRAM, PARTICULARLY THOSE OF YOU FROM OHIO! OHIO INTENDS TO BE A PLAYER IN ROUND 5.

- OVER THE NEXT TWO DAYS, YOU WILL HEAR FROM TECHNOLOGY DEVELOPERS FROM AROUND THE COUNTRY AND THE WORLD. I'M PROUD TO NOTE THAT MANY OF THESE PEOPLE AND PROJECTS ARE LOCATED IN OHIO.

- WHILE DEVELOPING CLEAN COAL TECHNOLOGIES IS IMPERATIVE, WE MUST ALSO EDUCATE THE POTENTIAL USERS, OUR CUSTOMERS, OF THEIR MERITS. THE JOB ISN'T OVER UNTIL THESE TECHNOLOGIES ARE IN REGULAR USE, CLEANLY AND COST-EFFECTIVELY USING THE VAST COAL SUPPLIES WITH WHICH THIS STATE, THIS COUNTRY, AND OTHER COUNTRIES ARE BLESSED.

- THAT IS WHY EVENTS SUCH AS THIS, AND THE TECHNOLOGY TRANSFER OPEN HOUSE THAT WAS HELD YESTERDAY ON THE SNOX TECHNOLOGY AT OHIO EDISON'S NILES STATION, ARE SO IMPORTANT. I KNOW MANY OF YOU HAD THE OPPORTUNITY TO VISIT THIS SITE, AND I HOPE YOU WERE IMPRESSED BY WHAT YOU SAW.

- BUT WE ARE NOT ONLY LOOKING FOR CUSTOMERS IN OUR OWN BACKYARD, WE ARE SEEKING CUSTOMERS IN THE GLOBAL MARKET PLACE. CLEAN COAL TECHNOLOGIES WILL HELP US SELL OUR COAL, BUT CLEAN COAL TECHNOLOGIES THEMSELVES ARE ALSO A VALUABLE COMMODITY. I COMMEND USDOE FOR RECOGNIZING THIS AND INITIATING A COAL AND TECHNOLOGY EXPORTS SECTION.

- I KNOW THAT BABCOCK & WILCOX OF OHIO PARTICIPATED IN ONE OF USDOE'S RECENT TRADE TRIPS, AND THAT EXPORTS ARE THE TOPIC OF A SESSION HERE TODAY. I'D LIKE TO NOTE THAT MR. JAMES SISTO, THE GOVERNOR'S MANAGER FOR EXPORT INITIATIVES, WILL BE IN ATTENDANCE AT TODAY'S 2:00 P.M. SESSION. PLEASE FEEL FREE TO LOOK HIM UP.

- I'D ALSO LIKE TO NOTE THAT OHIO IS FOLLOWING THE LEAD OF PRESIDENT BUSH IN ANOTHER, RELATED ARENA, THAT OF DEVELOPING AN OHIO ENERGY STRATEGY. COAL IS AND WILL REMAIN A VERY IMPORTANT COMPONENT OF OHIO'S ENERGY MAKE UP, BUT THERE ARE OTHERS. THIS EFFORT IS BEING ABLY LEAD BY MY COLLEGE, CRAIG GLAZER, AND I WILL DEFER TO HIM TO ELABORATE ON THIS TOPIC FURTHER.

- I KNOW THE TIME FRAMES ARE TIGHT, I KNOW THE ECONOMY IS TIGHT, BUT THE PROMISE OF CLEAN COAL TECHNOLOGIES IS SO GREAT. I CHALLENGE YOU TO FULFILL THE PROMISE.

- YOU'RE GOING TO HAVE A GREAT CONFERENCE, AND AGAIN, WELCOME TO OHIO.

**WEDNESDAY, SEPTEMBER 23**
**CLEVELAND, OHIO**
**CLEAN COAL TECHNOLOGY CONFERENCE**
**CHAIRMAN CRAIG A. GLAZER - PLENARY SESSION**
**"STATE REGULATORY VIEW OF COMPLIANCE STRATEGIES"**

Thank you for the kind introduction. I bring you greetings from the Ohio Public Utilities Commission. As the introduction indicates, I'm and attorney and am pleased to welcome you to Cleveland. Although Cleveland is not exactly the coal capital of Ohio, it is Ohio's largest metropolitan area, my home and a great city to hold a conference such as this. Cleveland is, in many ways, the comeback city--when I first moved here in 1979 it was in the throes of default, businesses were leaving it in droves and the City administration was at war with itself. If Cleveland can come back from adversity, so too can the coal industry which will be facing its own tough times in the months and years to come, next to the Indians.

The timing of this conference is also significant since we at the Ohio Commission are in about the fourth act of a long play with the American Electric Power Company over its compliance plans. And as the words to the song go, what a long strange trip its been. I want to tell you a little bit of the Ohio regulatory story on the Clean Air Act Amendment ("CAAA") Compliance because it has lessons in how you approach your state commissions.

As I am sure you are aware, Ohio is the state most affected by Phase I of the CAAA. With a new Governor in office barely three weeks, AEP announced in January of 1991, its intention to fuel switch at its Gavin power plant. With over six million tons of coal consumed a year, this was Ohio's largest coal fired power plant. The powerful coal interests in our legislature were not about to take that sitting down so they immediately began to work on drafting a bill which would make it more attractive for Phase I affected companies, and AEP in particular, to install scrubbers at its plant. This, of course, had the potential to set different parts of the state off at war with each other--the coal interests wanted the legislation to mandate our consideration of "externalities" namely, the socio-economic impact of job losses in coal country. Well, if you looked outside in Cleveland, surely you did not see too many coal miners walking around. The large industries in Cleveland, Akron and Canton with their Elcon position papers in hand, flexed their political muscle to kill this externalities thing. After much wrangling which only served to reaffirm the old adage that one should watch neither law nor sausage being made, we arrived at a consensus piece of legislation --one which called for us to consider the socio-economic externalities but to balance it with a determination of whether scrubbing or fuel switching is least cost. What is to me, perhaps the most significant amendment in our law which the Commission sponsored, the legislature said that in analyzing what is least cost for Phase I, we need to take a long term view--the planning horizon must be over both Phase I and Phase II. After extensive hearings, the Ohio Commission told AEP not to eliminate scrubbers as a compliance option. One of the key arguments which persuaded at least this Commissioner, was an argument raised by the Ohio Coal Development Office that if the scrubber could be made economic, it would provide that bridge which would enable our coal mines to remain open until new clean coal technology is developed--something to which our state has put many resources into.

At the same time, we urged AEP to get far more creative with its plan then simply a rigid stand alone all-hardware remedy to CAAA Compliance. We urged them to take a lead in development of an allowance pool for Phase I bonus allowances, to investigate the impact of selling rather than simply holding onto their allowances, to investigate reduced utilization as a compliance tool and other options such as, third party ownership of financing of its scrubber.

To its credit, the Company did investigate a number of these options and we are now at the tail end of the second hearing where specific Commission pre-approval of its plan is requested. We have also required each of our other electric companies to file plans and have since opened up dockets to develop a policy on emissions allowance trading, are in the midst of our second review of AEP's compliance plan and will be beginning, starting this afternoon, a review of the Clean Air compliance plans of Ohio's other utilities starting with Centerior. The lesson in all this is that although the initial planning and the risks of noncompliance or imprudent compliance must remain with the utility, that doesn't mean that regulators should simply stick their head in the sand and see people at the end of the line. That approach simply invites no risk taking, no development or investment in new technology, but instead either a costly all-hardware traditional approach or massive fuel switching in an attempt to avoid all risk. I have been speaking out on the need for state commissions to get focused on these issues and to tackle them sooner than later. Ohio passed its first pre-approval statute, one which gave a heavy emphasis to clean coal technology.

Although the Clean Air Act amendments are largely a hit on the coal industry, they do present some opportunities. Unfortunately, we tend to relive debates over the Act itself and let rhetoric rather than fact control us. The coal industry needs to begin to put packages together and come to the electric industry with reasonably-priced high sulfur coal and the emission allowances making it possible to burn it. Yet in my discussions with coal producers, I often times find precious little information or knowledge about the emissions trading market. This isn't just a market for the electric industries--in fact, the emissions allowance market provides great potential for the coal producer as well. In a similar vein, at least in Ohio, the term gas cofiring has caused an immediate negative reaction--there are those who are still reliving the battles over the Act who see any mention of natural gas as a plot by the gas industry to displace coal. I don't doubt that the gas industry, if it had its druthers, would like to displace coal as the number one power generation source. But given all the uncertainty facing the gas industry as a result of FERC Order 636, a commission, in my opinion, would be much more amenable to a gas cofiring strategy than a 100% gas conversion. We need to begin to put these packages together.

In short, the coal industry has to go beyond the initial Clean Air Act amendments decision, but instead get active in these critical markets. We as the regulators need to ensure that we set the stage which continues the development of clean coal technology and puts appropriate bridges in place until that technology is developed as we tried to do in our first Gavin Order. Regulators also need to get focused and provide guidance on these issues. It is only in these ways, that we can best utilize this vast resource of coal that we have been blessed with.

**Girard F. Anderson**
**President, Tampa Electric Company**
**U.S. DOE First Annual Clean Coal Technology Conference**
**Sept. 23, 1992**

Good morning. It is my pleasure to be here this morning to participate in DOE's First Annual Clean Coal Technology Conference. And to talk with you about a very special project for my company.

Tampa Electric Company is currently in the process of permitting a new 260-megawatt generating facility in Polk County Florida.

In my 33 years with the company, I've personally been involved with the design, construction and management of 2700 megawatts of new generating capacity. But this unit is unlike any other we've built before -- thanks to Round Three of the DOE's Clean Coal Technology Program.

After an exhaustive evaluation of power generation technologies -- and selection by the DOE for CCT funding -- Tampa Electric is very pleased to be designing and building a truly state-of-the-art power plant.

Our new 260-megawatt Polk Power Station is an "Integrated Gasification Combined Cycle" unit. And as a part of our panel today, I'd like to provide Tampa Electric's perspective on entering into a Clean Coal Technology project such as this; what we expect from the project; and a bit about our strategy for maintaining the public support we've built over the past year.

I'd like to start with a quick glance at the Tampa Electric system. We are an investor-owned electric utility serving West Central Florida since 1899. We have 3,200 employees and presently provide electricity to more than 467,000 retail Customers. Through wholesale power arrangements, we also serve a variety of other communities, municipalities and cooperatives.

Tampa Electric has five power plants, three adjacent to Tampa Bay and two inland, smaller plants.

Tampa Electric's generation is 99 percent coal fired. And because we have sister companies that operate coal mines in Kentucky and Tennessee, and a transfer terminal and water transportation system headquartered near New Orleans, we have the advantage of an economical supply of coal and a reliable water delivery system.

Our experience with coal over the years has been very positive. Coal prices have held steady and we've avoided dependency on foreign oil. We have long believed that reliance on America's most abundant and lowest cost natural energy source -- coal -- is the best choice for our industry and our customers.

But with the new Clean Air Act Amendments and growing public environmental pressures, making the choice of coal today is not always easy.

Especially when you consider that new power generating facilities will not be granted any SO2 emissions allowances. Those allowances will either have to be purchased on the "allowance market" or generated internally from reductions achieved at the company's existing power plants.

So the pressure to keep sulfur dioxide emissions from new power plants to the absolute minimum is both an environmental and economic necessity for today's utilities.

That's why we view this Clean Coal Technology project as a very natural solution for Tampa Electric. By selecting the IGCC technology, our Customers will benefit from a long-term, reliable, economically priced source of fuel. Our environment will benefit from the superior sulfur dioxide and other emissions reduction performance of this unit. And our company will benefit by producing reliable generation in a way that economically meets the requirements of the Clean Air Act.

We are excited to play a role in the development of better ways to utilize coal -- ways that bring such benefits to our industry, its Customers, and our environment.

Steve Jenkins, from TECO Power Services -- our sister company -- will provide an indepth look at the technology of the Polk Power Station later today in one of your afternoon sessions. But for your reference this morning, let's a take a quick look at the configuration of this unit.

It is a first-of-its-kind combination of two leading technologies. The first technology is called "combined cycle," which is common to the utility industry.

Combined cycle is the most efficient commercially available method of producing power today. Combined cycle is more efficient because it uses exhaust energy from combustion turbines to produce additional electricity.

The second technology we're using is called "coal gasification," in which coal is converted to a clean-burning gas. Coal gasification is not new to the chemical or refinery industry, but it is new to the utility industry.

Our Polk Power Station will be the first commercial integration of these technologies.

This new integration of technologies combines the high efficiency of the combined-cycle design with the low cost of coal for fuel.

And this unique design makes the Polk unit significantly more efficient than a conventional power plant.

Our work on the Polk Power Station actually began more than five years ago. Like all electric utilities, we are constantly evaluating and reforecasting our Customers' energy demand and generation supply. We built our last power plant in 1985, a 441-megawatt coal-fired unit with wet limestone flue-gas desulfurization.

Since then, our Customer base has grown by 18 percent -- or 80,000 Customers -- and it continues to grow.

So by the late 1980s, our forecasts were showing that we would be able to meet half of our Customers growing energy needs through the year 2000 with energy saved through conservation, load management and cogeneration.

But by 1989, our forecast showed that we would need to have 260 megawatts of new capacity in place in 1996.

And that's one of the beauties of this project. By selecting the IGCC configuration, we will place 150 megawatts of peaking capacity on line via a combustion turbine in mid-1995. And then add the gasification plant, heat recovery steam generator and steam turbine to convert the plant to baseload, coal-fired generation by 1996.

The IGCC technology not only meets our expansion plan criteria, but it meets out our environmental criteria as well.

This unit will achieve a <u>minimum</u> sulfur removal rate of 96 percent with its conventional cold-gas cleanup technology. With its demonstration technology -- the hot-gas cleanup system -- it has the potential for even higher removal levels. We are working daily with the manufacturer of the hot-gas cleanup system to design for higher removal rates. And again, Steve Jenkins will talk more about that later today.

Overall, the Polk unit design is about nine to twelve percent more efficient than conventional baseload pulverized coal units. That means we will be burning less coal to produce the same amount of electricity. This higher unit efficiency translates into fewer emissions -- again adding to better environmental performance.

We are making progress on the technology design with our major equipment/system suppliers in this project: General Electric, General Electric Environmental Services, and Texaco.

But just as important as our progress with the technology design, is the level of public and media support we've been able to build for this project.

The roots of our success with public acceptance began back in 1989 when we formed a 17-member "Siting Task Force" to help us in the selection of our power plant site. We formed this citizen's advisory group in 1989 when our expansion plan showed an upcoming need for new capacity by the mid-1990s.

This blue ribbon panel was made up of environmentalists, educators, economists and community leaders.

Here are some of the groups who had members on the task force. We made sure that at least half of the group was comprised of environmentalists -- because we knew that protecting the environment would be the number one priority in selecting the plant's technology and site.

The Siting Task Force began with a hard look at our generation expansion plan, our conservation programs and the generation technologies under consideration.

Once they were comfortable with our need for new generation, they began an indepth evaluation of nearly 40 sites in a six-county area.

The task force ultimately decided -- after much debate -- that it was better to recommend sites that had already been touched by industry. Their final recommendation was the company's choice of three former phosphate mining tracts located in southwest Polk County.

The task force believed that it was best -- from both an environmental and economic standpoint -- to place previously mined phosphate land back into productive use.

The Siting Task Force's work was conducted in the open, with local media attending each of their lengthy sessions. So when the announcement of the final site selection was made, there were no surprises. The public had been kept abreast of the site search all along.

With the site recommendation in hand, we began to move forward with our land acquisition, plant technology and permitting activities. And as that process began, we continued our communications with our Customers, particularly those in Polk County nearest to the site.

When the IGCC technology and DOE participation were identified and secured, we immediately made personal contact with local government and community leaders -- prior to the public media announcements.

Last year we began a periodic newsletter to Polk County residents, talking about the plant's technology, site and environmental protection features.

And, this year, we held a series of personal community meetings with the Polk residents, presenting a slide show, displaying an exhibit, and answering any questions.

The DOE held a similar meeting in Fort Meade Florida this past month called a "Scoping Meeting." More residents came to speak in favor of the plant than those who came to speak out against the plant.

We have taken the communications strategy for our Polk Power Station seriously. Our communications people serve on our project management team for the plant, just as the engineers, accountants and legal counsel.

We realize that we don't operate in a vacuum. That, instead, we operate under the close scrutiny of the media and in the "court of public opinion."

I believe that this approach of open and regular communications with Customers and the media has made all the difference in terms of the smooth progress we've made to date.

I also think the process we have used shows that, even today, we can successfully site and build coal-fired generation.

In a recent survey, three out of four of our Customers agreed that we need to build this facility.

And two out of three think we made the right decision to use coal.

Many of you know that these results are virtually the opposite of current national trends in public opinion.

We will continue with this communications-based approach to this project, just as we have with all of our operations within Tampa Electric.

We are confident we can manage this process successfully and see this new Clean Coal Technology unit become a reality for our Customers, our company and the DOE.

One of our sister companies, a wholesale power generation company called TECO Power Services, is providing the day-to-day project management for this unit as well as all the interface activities with the DOE.

TECO Power Services will be the one to push forward with the commercialization and marketing of this technology once it's successfully demonstrated at Tampa Electric.

This Clean Coal Technology unit is an innovative and natural solution to our need for clean, reliable power generation.

With our new Polk Power Station, Tampa Electric will produce reliable generation from an abundant domestic fuel source. We will achieve superior environmental performance. We will provide cost-effective and economical electricity to our Customers. And we will help the DOE in its efforts to boost commercialization of Clean Coal Technologies that greatly reduce emissions and help provide for future energy needs in an environmentally acceptable manner.

This IGCC unit is a dynamic and innovative project of which we are very proud. And we are very much looking forward to beginning construction in 1994; to bringing the combustion turbine on line in 1995; and to bringing the full IGCC unit on line in 1996.

We thank the DOE for the technical and financial support to make this project possible.

And I look forward to being able to report on the success of this project at perhaps the Fifth Annual DOE Clean Coal Technology Conference in '96.

* Comments bv Garv L. Neale durina Plenarv Session of the First Annual Clean Coal Technoloav Conference on Seotember 23, 1992.

Good morning! Todav I'd like to discuss the factors that went into Northern Indiana Public Service Comoany's decision to enter in our Clean Coal Technology Project. I will also discuss NIPSCO's history with respect to scrubbers -- a historv that has left us in an excellent position to meet the Clean Air Act Amendments of 1990.

NIPSCO services a territory covering the Northern one-third of Indiana including 20 percent of the nation's steel making capacity. Our load is about 50 percent industrial, and we serve an additional 300,000 residential customers. Our industrial customers can create loads that swing 600 to 800 megawatts from minute to minute. The manufacturing load is highly automated with about 1500 MW of computer control processes. Because these industrial customers require a high quality power, NIPSCO has built generating stations close to our load. This has led to high generating costs for NIPSCO.

We currently operate four (4) generating stations. Three are located on the shores of Lake Michigan -- the D.H. Mitchell Station, the Bailly Station (the site of our Clean Coal Project), and the Michigan City Station. Our fourth, the R. M. Schahfer Station, is located in Wheatfield, Indiana, approximately 30 miles south of Lake Michigan. Due to our close proximity to Chicago, our three lakeshore stations are in a non-attainment zone, while the fourth affects the non-attainment zone. Because of this location, we operate under the strictest clean air standards in the United States.

When the Clean Air Act was passed in 1990, eight of our eleven units were already in compliance with both Phase I & II of the Act. That left three units be be brought into compliance. On Bailly's Units 7 and 8, we have installed an Advanced Flue Gas Desulfurization System which is part of the Clean Coal Technology Program. Michigan City Station's Unit 12 will blend fuel for Phase I and switch fuel for Phase II. We are now in compliance at all of our stations through Phase II. This has not been an easy road.

The environmental requirements of the 70's were relatively few for most utilities. NIPSCO was the exception.

Operating in a non-attainment area made NIPSCO do things differently than other utilities. In the mid 70's, we entered into a EPA joint venture at our D.H. Mitchell Generating Station. The Wellman Lord Scrubber produced a reusable by-product sulfur; but it was a very complicated system. The System was owned by NIPSCO but was operated by Chemical plant experts. In the end, the system was too complicated and was decommissioned after the test program. Our other units complied with environmental regulations of the 70's easily by switching to low sulfur coal.

Although this compliance technique was fairly easy, it was not without costs. The low sulfur coal comes from Colorado and Wyoming adding a large transportation cost on top of the coal costs. To overcome supply concerns of low sulfur coal, long term (15-20 years) contracts were entered into by NIPSCO and other utilities. These coals became even more costly in the 80's when these long-term contracts were broken.

The environmental requirements of the 80's mandated the use of the scrubber. NIPSCO had made the decision to add two or more units to our Schahfer Generating Station each rated at 334 megawatts. The limestone scrubbers typical of the late 70's and early '80's were unreliable due to pluggage and chemical problems.

Instead of the problem-plagued limestone scrubbers, we decided to go with a dual alkali system with its clear scrubbing liquor to assure a highly reliable unit. These units were state-of-the-art systems for the 80's. The by-product was calcium sulfite, a by-product that requires a large landfill. These units were designed to cycle due to the characteristics of the overall load. To keep these units operating reliably, a lot of redundant equipment was installed. For example, eight (8) absorbers and eight (8) filters were installed to assure reliability. This drove up the initial cost and the associated operating and maintenance costs of the scrubbing system.

The on-site disposal area at Schahfer takes approximately 200 acres of the 4,000 acre plant. After 22 years of operation, it will reach a height of 67 feet. This large mountain has become an irritation to local residents and environmental groups. These problems were ones we didn't want to repeat. In 1989, they also led to a negative attitude toward scrubbing when we were facing the decision on environmental compliance at our three (3) Phase I affected units.

The environmental requirements of the 90's are more stringent. Early on, we made the decision to go with a Clean Coal Technology that produced a useable by-product. The use of Clean Coal Technology allows us to be a leader in the environmental field and allows us to be competitive.

The Pure Air Advanced Gas Desulfurization (AFGD) System at our Bailly Generating Station was selected during the second round of the Department of Energy's Clean Coal Technology Program. It will receive $64 million of the $150 million of the project's cost. It is a forced oxidation limestone scrubber with both units being scrubbed by one single absorber module producing a saleable by-product, gypsum. This project will prove that high SO2 removal can be achieved at a cost substantially lower than the conventional scrubbers.

The Project has had to overcome many hurdles before becoming reality. One was to obtain a Certificate of Public Convenience and Necessity from the Indiana Utility Regulatory Commission (IURC). This pre-approval eliminated the concern that the IURC might second guess our decision to scrub. Our investigation into our options for reducing the SO2 emissions from Bailly Generating Station had initially revealed three (3) options:

- High sulfur coal with a scrubber
- Low sulfur coal
- Natural gas

Our decision to burn high sulfur coal and scrub the units was upheld by the IURC and a certificate was granted in April, 1990. This decision proves to be the lowest cost option to our customers in the long term.

The innovative feature that makes this scrubber "State of the Art" are as follows:

1. Single 600 MW absorber fed from the multiple units
2. Waste evaporation system
3. Direct limestone injection
4. Saleable by-product -- gypsum. This was the only choice to get the local environmentalists (such as Save the Dunes, Sierra Club, and the Issac Walton League) to support this project.
5. Air rotary sparger
6. Owned and Operated by Pure Air.

This scrubber presents many improvements over the system installed at our Schahfer Station. The problematic rotary vacuum filters are replaced by more efficient centrifuges. Not only are they more efficient in dewatering capability, but they also required less space. The landfill is replaced with a wallboard plant. The by-product is being sold to U.S. Gypsum Company for use in its East Chicago, Indiana, plant. The gypsum generated by AFGD is enough to produce wallboard for 20,000 single family homes in the Chicago land area. I stress Chicago land area -- the market has to be close to the power plant for the economics to work.

What lessons have we learned in the last three decades about scrubbers? We have realized that, "scrubbers are, in fact, chemical plants." Utilities are good at producing power but as far as scrubbers are concerned, it is best to leave it up to a chemical company. We have formed a partnership with Pure Air, a general partnership of two chemical companies -- Air Products & Chemical, Inc. and Mitsubishi Heavy Industries America, Inc. The Bailly scrubber is owned and operated by Pure Air.

The role of the Clean Coal Technology Program in NIPSCO's Clean Air Compliance is two-fold. First, it has allowed NIPSCO to remain an environmental leader and remain an industry competitor. NIPSCO is now "clean" through the year 2000. Secondly, it allows us to continue to use the nation's most abundant fuel source -- coal. NIPSCO has balanced the energy source risk by using both high and low sulfur coal. And finally, we have taken the high road by cleaning up early. The whole team at NIPSCO has a new attitude and it has created a new environmental awareness at NIPSCO. We have adopted a new slogan -- "NIPSCO: producing energy that works for you and the environment."

I thank the Department of Energy for allowing me to speak before this group and also allowing NIPSCO to be the host site for this Clean Coal Project.

# COAL AND COAL TECHNOLOGY:

# ENERGY TO DRIVE A WORLD EVOLUTION

REMARKS

BY

THOMAS ALTMEYER

SENIOR VICE PRESIDENT

NATIONAL COAL ASSOCIATION

TO THE

FIRST ANNUAL

CLEAN COAL TECHNOLOGY CONFERENCE

CLEVELAND, OHIO

SEPTEMBER 23, 1992

ON BEHALF OF GENERAL RICHARD LAWSON AND THE MEMBERS OF THE NATIONAL COAL ASSOCIATION, I WOULD LIKE TO THANK THE DEPARTMENT OF ENERGY FOR THE OPPORTUNITY TO PARTICIPATE. DICK REGRETS NOT BEING ABLE TO JOIN YOU TODAY, HE IS OVERSEAS WHERE HE CHAIRED THE INTERNATIONAL COMMITTEE ON COAL RESEARCH MEETING IN LONDON LAST WEEK AND IS CHAIRING A SESSION OF THE WORLD ENERGY COUNCIL'S 15TH CONGRESS IN MADRID ON ENERGY NEEDS AND POPULATION GROWTH.

TO PARAPHRASE REMARKS ONCE MADE AT A DINNER FOR NOBEL LAUREATES, THE WORLD HAS NOT SEEN THIS MUCH TALENT FOCUSED ON COAL TECHNOLOGY AND ENERGY GATHERED IN ONE PLACE SINCE EDISON TOILED AT HIS WORKBENCH -- ALONE.

THE TIME RUSHING ON AS THIS CENTURY CLOSES IS IN NEED OF THIS TECHNOLOGY AND YOUR TALENT NO LESS, AND PERHAPS MORE, THAN THE WORLD WAS OF EDISON'S JUST BEFORE THE CENTURY BEGAN.

AS HAS BEEN SAID, "TECHNOLOGY MADE LARGE POPULATIONS POSSIBLE; LARGE POPULATIONS NOW MAKE TECHNOLOGY INDISPENSABLE."

TECHNOLOGY SOLVES PROBLEMS. TECHNOLOGY IS THE WIT OF HUMANKIND MADE TANGIBLE AND APPLIED.

AS EVIDENCED THE ATTENDANCE HERE AND THE PHENOMENAL SUCCESS OF THE JOINT GOVERNMENT-INDUSTRY CLEAN COAL TECHNOLOGY PROGRAM, WE ARE AT THE THRESHOLD OF AN EXPLOSION OF COAL UTILIZATION OPTIONS UNPARALLELED IN THE HISTORY OF ANY ENERGY SOURCE.

THE ENERGY PRECIPITATED CRISES OF THE '70's AND '80's CONVEY A LESSON. FOR GEOPOLITICAL AND ECONOMIC REASONS, OUR NATION CANNOT PERMIT ITSELF TO REMAIN STRATEGICALLY DEPENDENT ON IMPORTED ENERGY. WE MUST USE ALL OUR DOMESTIC ENERGY RESOURCES - COAL, OIL, GAS, NUCLEAR, RENEWABLE, CONSERVATION AND EFFICIENCY.

OUR CHALLENGE IS TO FRAME THE PROBLEMS ACCURATELY AND COMPREHENSIVELY FOR TECHNOLOGY, AND TO DO IT IN WAYS THAT ENABLE THE FUTURE RATHER THAN CONSTRICT IT.

EVERYTHING IN A MODERN ECONOMY AND RELATED TO A MODERN STANDARD OF LIVING BEGINS WITH ENERGY.

WE KNOW THE FOLLOWING ABOUT ENERGY AND THE FORCES AFFECTING ENERGY:

- GLOBAL DEPENDENCE ON IMPORTED OIL HAS CAUSED, IN LESS THAN TWO DECADES, TWO WORLDWIDE ECONOMIC DISLOCATIONS AND THE MAJOR GEOPOLITICAL DISRUPTION OF THE PERSIAN GULF WAR;
- THE OIL SITUATION WILL GET WORSE -- NOT BETTER; DECLINING WORLD RESERVES WILL GIVE THE GULF PRODUCERS INCREASED MARKET DOMINANCE AND THE WORLD ECONOMY GREATER INSTABILITY;
- AMERICAN OIL IS IN STEEP DECLINE; OUR IMPORT-DEPENDENCE WILL INCREASE UNLESS ADDRESSED; SO WILL OUR ECONOMIC VULNERABILITY;

- GLOBAL POPULATION WILL GROW BY 3.2 BILLION PERSONS IN THE NEXT 30 YEARS OR SO;
- THIS POPULATION WILL REQUIRE ECONOMIC DEVELOPMENT TO RAISE LIVING STANDARDS AND KEEP THE WORLD PEACEFUL;
- THE HUGE FORMER EMPIRE OF THE FORMER SOVIET UNION WILL REQUIRE THE SAME; FOR ECONOMIC CHAOS CAN PRODUCE DANGEROUS DICTATORSHIPS NO LESS THAN DEMOCRACIES.
- THESE CHORES WILL REQUIRE ENORMOUS AMOUNTS OF ENERGY AND CONSIDERABLE ASSISTANCE;
- ONLY THE INDUSTRIALIZED NATIONS, ESPECIALLY AMERICA, CAN DO THIS; THEY HAVE THE TECHNOLOGY AND THE MARKETS;

- THE INDUSTRIALIZED NATIONS WILL REQUIRE ADEQUATE, LOW-COST ENERGY TO MAINTAIN ECONOMIC STRENGTH FOR THE UNDERTAKING AND THEIR OWN STABILITY;
- WORLD COAL RESERVES CONTAIN ABOUT THREE TIMES THE ENERGY OF WORLD OIL RESERVES; AND AMERICA'S RECOVERABLE COAL IS THE ENERGY EQUIVALENT OF WORLD OIL RESERVES;
- NEW ELECTRIC GENERATING CAPACITY WILL BE A PRIMARY CONCERN AT HOME AND ABROAD;
- COAL IS WELL-SUITED FOR ELECTRIC POWER GENERATION;
- THE UNIFICATION OF WESTERN EUROPE AND THE REORIENTATION OF THE ECONOMIES IN THE FORMER SOVIET EMPIRE WILL RESTRUCTURE WORLD COAL PRODUCTION AND DEMAND;

- AND, TO CLOSE THIS SUMMARY, THE NEWLY-RAISED POSSIBILITY OF AN ENERGY-INDUCED GLOBAL CLIMATE CHANGE MUST BE TREATED SERIOUSLY;

ENERGY IS CENTRAL TO EVERY HOPE AND ASPIRATION FOR THE FUTURE.

ENERGY WILL DETERMINE THE QUALITY OF EVERY ENVIRONMENT CRITICAL TO THE SURVIVAL OF HUMANKIND -- THE ECONOMIC, THE POLITICAL AND THE NATURAL.

THESE ENVIRONMENTS ARE GLOBAL. THEY ARE AS INTER-DEPENDENT AS ANYTHING FOUND IN NATURE. EACH ACTS AND REACTS, ONE ON THE OTHERS, THE OTHERS ON ONE.

THE POLITICAL ENVIRONMENT IS INFLUENCED BY THE ECONOMIC, WHICH DEPENDS ON ENERGY. THE NATURAL IS INFLUENCED BY THE ECONOMIC AND BY THE PRODUCTION AND USE OF ENERGY.

WITH ENOUGH ENERGY, WELL AND WISELY USED, ALL THREE ENVIRONMENTS PROSPER, AND MANKIND WITHIN THEM.

WITH TOO LITTLE, THE CLOCK OF PROGRESS BEGINS TO WIND BACKWARD -- TOWARD THE LONG-REMEDIED ABUSES OF THE EARLY INDUSTRIAL REVOLUTION; TOWARD THE SLASH-AND-BURN ERA OF AGRICULTURE; TOWARD SUBSISTENCE AND WANT; TOWARD UNREST AND WAR; AND TOWARD NEW HITLERS, IF NOT STALINS, AMONG THE 3-BILLION.

THUS IT ALL BEGINS WITH ENERGY -- AND WITH BALANCE: FOR TO SACRIFICE ONE ENVIRONMENT TO THE OTHERS, OR THE OTHERS TO ONE, IS TO PUT THE FUTURE AT RISK. IMPORTANT PIECES ARE BEING PUT IN PLACE FOR DEALING WITH THE FUTURE -- FOR SHAPING A NEW ERA.

A NATIONAL ENERGY SECURITY ACT HAS PASSED BOTH HOUSES OF CONGRESS, AND BOTH VERSIONS HAVE STRONG COAL SECTIONS. THE CONFEREES ARE MEETING AND AGREEMENT WILL BE REACHED SHORTLY.

WE WILL HAVE A NATIONAL ENERGY SECURITY ACT SIGNED INTO LAW BEFORE THE ELECTIONS -- AND THE COAL SECTION WILL BE STRONG.

THIS PAST JUNE THE BUSH ADMINISTRATION HELD FAST AGAINST GREAT PRESSURE AND BROUGHT INTO BEING AN INTERNATIONAL AGREEMENT ON GLOBAL CLIMATE CHANGE THAT DOES NOT -- LET ME EMPHASIZE, DOES NOT -- REQUIRE SIGNATORIES TO PRECLUDE OR PUNISH COAL USE.

THE UNITED NATIONS' CONVENTION ON CLIMATE CHANGE ALLOWS AMERICA TO MOVE AHEAD WITH PLANS TO INCREASE ENERGY SECURITY AND TO FREE FUTURE WORLD DEVELOPMENT FROM THE THREATS OF IMPORTED-OIL DEPENDENCE.

IN WORLD ENERGY, COAL USE IS FORECAST TO ALMOST EQUAL WORLD OIL DEMAND BY THE YEAR 2000 AND THEN TO EXCEED IT BY A FACTOR OF ALMOST TWO BY 2025.

IN THE UNITED STATES, COAL DEMAND IS PROJECTED TO BE 1.1-BILLION TONS A YEAR BY THE YEAR 2000 AND TO REACH 1.5 BILLION TONS BY 2010. WE CURRENTLY USE A LITTLE OVER 1-BILLION TONS.

LET ME OFFER A PERSPECTIVE ON DEMAND.

FOREMOST, FUTURE DEMAND IS HEAVILY INFLUENCED BY PRESENT PERFORMANCE.

PERFORMANCE IS THE REASON U.S. COAL PRODUCTION REACHED 1-BILLION-TONS-A-YEAR NO LESS THAN FIVE YEARS AHEAD OF OFFICIAL FORECASTS.

THE ELECTRIC-UTILITY BURN INCREASED BY 36 PERCENT DURING THE 1980s -- FROM 569-MILLION TONS IN 1980 TO 772-MILLION TONS IN 1990. DESPITE THE 1991 ECONOMY, THE UTILITY BURN STILL SET A RECORD OF 776-MILLION TONS.

THE 1992 BURN IS FORECAST AT 794 MILLION TONS -- ANOTHER RECORD.

THE NCA FORECAST FORESEES 1992 PRODUCTION OF 1-BILLION-AND-29-MILLION TONS AND RECORD CONSUMPTION OF 1-BILLION-AND-26 MILLION TONS.

BEHIND THIS GROWTH IS ONE OF AMERICA'S LITTLE-NOTED INDUSTRIAL SUCCESS STORIES.

COAL-MINING PRODUCTIVITY INCREASED IN EVERY YEAR OF THE 1980s -- GREW BY MORE THAN 126 PERCENT IN THE 12 YEARS BETWEEN 1978 AND 1990.

IN SHORT, THE U.S. COAL INDUSTRY IS ONE OF AMERICA'S MOST MODERN, MOST COMPETITIVE INDUSTRIES OF ANY KIND.

IN CONSEQUENCE, THE REAL PRICE OF COAL HAS GONE DOWN EVERY YEAR SINCE 1978 IN TERMS OF 1982 DOLLARS. THE ACTUAL AVERAGE PRICE PER TON IN 1990 WAS SLIGHTLY LOWER THAN 1978's.

AND COAL -- ON THE COMPETITIVE BASIS OF COST -- BECAME THE FUEL OF CHOICE IN GENERATING NEARLY 60 PERCENT OF AMERICA'S POWER. THIS PERFORMANCE SPEAKS FOR ITSELF.

AS A RESULT, COAL-FIRED ELECTRIC-POWER GENERATION WAS A CENTRAL FACTOR IN DRIVING THE ECONOMIC GROWTH OF THE 1980s, AND IT SUSTAINS ACTIVITY NOW.

COAL ALSO SERVED WHEN OTHER GENERATION FALTERED -- WHEN NUCLEAR PLANTS WENT OFF-LINE FOR LONG PERIODS AND WHEN LOW WATER KNOCKED OUT HYDROPOWER.

FOR THE LONGER TERM, THE DEPARTMENT OF ENERGY FORESEES A 46 PERCENT INCREASE IN THE POWER GENERATION COAL-BURN BETWEEN 1990 AND 2010.

THE PROJECTION IS BASED ON THE EXPANDING USE OF ELECTRICITY IN THE ECONOMY. IN ADDITION TO PERFORMANCE IT RECOGNIZES THAT SIGNIFICANT COAL-FIRED CAPACITY WILL BE LIFE-EXTENDED, AND THAT COAL WILL WIN MUCH OF THE LARGE INCREMENT OF NEW CAPACITY AMERICA WILL NEED, ESPECIALLY AFTER THE YEAR 2000.

THE QUESTION IS OFTEN ASKED, WHAT IS THE FUTURE OF COAL IN POWER GENERATION GIVEN THE CLEAN AIR ACT AND THE CLIMATE CHANGE CONTROVERSY?

IN PERSPECTIVE, THE QUESTION IS, WHAT IS THE FUTURE OF POWER WITHOUT COAL? AND OF AMERICA WITHOUT ADEQUATE POWER?

ONLY COAL FACES NONE OF THE MARATHON SAFARIS THROUGH THE BRAMBLES AND BRIARS OF REGULATION AND LITIGATION THAT CONSTITUTE DUE PROCESS; OR NEEDS NO IMMEDIATE EXPANSION OF INFRASTRUCTURE TO GUARANTEE AVAILABILITY AND RELIABILITY.

ONLY COAL CAN BE COUNTED ON TO DELIVER THE INCREMENTS OF POWER NEEDED TO KEEP THE AMERICAN ECONOMY GROWING AND INTERNATIONALLY COMPETITIVE.

NO OTHER FUEL OFFERS THE SAME ADVANTAGES: SUITABILITY; AVAILABILITY; DEPENDABILITY; LOWEST COST; AND A RAPIDLY ADVANCING, HIGH-EFFICIENCY BASE OF COMBUSTION TECHNOLOGY.

COAL WILL CONTINUE TO ENERGIZE AMERICA.

U.S. COAL ALSO WILL EXERT MORE INFLUENCE ON THE BALANCE OF TRADE. REMEMBER, WORLD COAL DEMAND SHOULD ALMOST EQUAL WORLD OIL DEMAND IN LESS THAN 10 YEARS.

EXPORT DEMAND FOR U.S. COAL IN 1992 SHOULD REACH 114-MILLION TONS -- ANOTHER RECORD. WHILE OIL IMPORTS ACCOUNT FOR A MAJOR SHARE OF OUR BIG TRADE DEFICIT, COAL EXPORTS ADD MORE THAN $4.5 BILLION TO THE PLUS-SIDE OF THE LEDGER.

WORLDWIDE, MANY NATIONS IN NEED OF POWER GENERATION ARE LOOKING AT TWO THINGS; THE OIL IMPORT SITUATION AND THE ADVANTAGES OF COAL.

THESE ADVANTAGES WILL COME TO INCLUDE HIGH EFFICIENCY, AND CLEAN COMBUSTION TECHNOLOGY FROM THE UNITED STATES.

ACTUAL DEMAND WILL BE HEAVILY INFLUENCED BY PERFORMANCE -- OF THOSE WHO PRODUCE COAL, OF THOSE WHO MOVE IT INTO COMMERCE, OF THOSE WHO DEVELOP COMBUSTION TECHNOLOGY, AND OF THOSE WHO APPLY IT.

THE PENDING NATIONAL ENERGY SECURITY ACTS IN THEIR COAL SECTIONS ADDRESS COMBUSTION TECHNOLOGY AND THE DEPLOYMENT OF THAT TECHNOLOGY.

THERE ARE DIFFERENCES BETWEEN THE SENATE BILL AND THE HOUSE BILL, BUT THOSE DIFFERENCES ARE OF DETAIL AND NOT OF MEANS AND THRUST AND PURPOSE.

BASED ON THE BUSH ADMINISTRATION'S NATIONAL ENERGY STRATEGY, THE ACT HAS TWO PURPOSES:

- FIRST, TO GUARANTEE AMERICA ADEQUATE ENERGY AT REASONABLE COSTS;

- AND THEN, IN A NON-PIECEMEAL, INTEGRATED WAY, TO DEAL RESPONSIBLY WITH REASONABLE ENVIRONMENTAL CONCERNS, ESPECIALLY THE POLITICAL QUESTION OF CLIMATE CHANGE.

BOTH THE STRATEGY AND THE ACT RECOGNIZE THE IMPORTANCE OF AMERICA'S 268-BILLION TONS OF RECOVERABLE COAL RESERVES AND THE ADVANTAGES OF COAL USE IN ELECTRIC POWER GENERATION.

THE COAL SECTION DIRECTS:

- THE ESTABLISHMENT OF PROGRAMS FOR RESEARCH, DEVELOPMENT, DEMONSTRATION, AND COMMERCIAL APPLICATION OF ADVANCED TECHNOLOGIES FOR COAL PREPARATION, UTILIZATION, AND EMISSION REDUCTION;

- AND DEVELOPMENT OF ADVANCED CLEAN COAL TECHNOLOGIES WHICH COULD ALL BUT DOUBLE EFFICIENCY INCREASES AND DRAMATICALLY REDUCE CARBON DIOXIDE EMISSIONS.

WITH CLEAN COAL TECHNOLOGIES, INVESTMENT IN PRODUCTIVITY INCREASES BECOME INVESTMENT IN EMISSIONS CONTROL; AND EMISSIONS CONTROL BECOMES INVESTMENT IN PRODUCTIVITY. IT IS THE CLASSIC WIN-WIN SOLUTION.

DEPLOYMENT WILL BE GOOD FOR THE DOMESTIC ECONOMIC AND NATURAL ENVIRONMENTS.

BUT THE ACT DOES NOT DIRECT DEPLOYMENT AND DOES NOT DEMAND THAT ELECTRIC UTILITIES USE COAL. IT LEAVES THOSE CHOICES TO THE MARKET.

EQUALLY IMPORTANT IN WORLD LEADERSHIP, THE ACT FOSTERS THE EXPORT OF BOTH U.S. COAL AND CONVENTIONAL AND EMERGING CLEAN COAL TECHNOLOGY.

EXPORT WILL MAKE RELIABLE, LOW-COST ENERGY AVAILABLE TO THE POPULATION-RICH BUT ENERGY-POOR DEVELOPING NATIONS IN THE GEOPOLITICAL DOORYARDS OF THE ADVANCED NATIONS.

IT WILL ALLOW CHINA AND INDIA TO USE THEIR COAL IN WAYS TO BENEFIT THEIR DEVELOPMENT AND THE GLOBAL ENVIRONMENT.

AND IT WILL PROVIDE THE ECONOMIC MEANS OF CLEANING UP THE HIGH-POLLUTION ECONOMIES OF STRUGGLING NATIONS SUCH AS THE SOVIET UNION AND THOSE OF EASTERN EUROPE.

EXPORT WILL BE GOOD FOR THE INTERNATIONAL ECONOMIC, NATURAL AND POLITICAL ENVIRONMENTS.

THE ENERGY SECURITY ACT ALSO CONTAINS STRONG PROVISIONS FOR THE RESEARCH, DEVELOPMENT AND DEPLOYMENT OF ADVANCED COAL TECHNOLOGIES FOR NON-TRADITIONAL USES OF COAL.

ADDITIONALLY, THROUGH ENCOURAGING THE EXPANDED USE OF ELECTRICITY IN BOTH TRADITIONAL AND NEW APPLICATIONS SUCH AS THE ELECTRIC VEHICLE, THE ACT WILL FURTHER THE USE OF COAL WITH AN IMPROVING ENVIRONMENT.

SO WE'VE COME A LONG WAY IN 1992, BUT CHALLENGES REMAIN.

FOUR YEARS AGO THIS PAST SUMMER, A NASA SCIENTIST TESTIFIED BEFORE A SENATE COMMITTEE THAT THE HEAT AND DROUGHT OF THAT SUMMER WAS A GREENHOUSE WARMING SIGNAL. BEFORE THE END OF THE YEAR, GLOBAL CLIMATE CHANGE AND DISASTER SCENARIOS HAD BEEN COVER STORIES ON THE MAJOR PERIODICALS AND NEWSPAPERS. A POLITICAL ISSUE TO CARRY MULTIPLE SOCIAL, ECONOMIC AND POLITICAL AGENDAS HAD BEEN BORN.

IT HAS TAKEN FOUR YEARS AND MUCH AGITATION FOR THE SOMETIMES MELODRAMATIC SCARE-ISSUE TO PLAY OUT IN THE INTERNATIONAL ACCEPTANCE OF THE BUSH ADMINISTRATION'S "NO REGRETS" POLICY AT THE RIO "EARTH SUMMIT."

"NO REGRETS" IS AN ALTERNATIVE TO CHOKING DOWN ECONOMIC ACTIVITY BY LIMITING THE USE OF CARBON DIOXIDE-PRODUCING FOSSIL FUELS. THE CHOKE-DOWN IS THE APPROACH FAVORED BY MANY OF AMERICA'S ECONOMIC COMPETITORS AND OUR CAREER ENVIRONMENTAL ACTIVISTS. "NO REGRETS" INCLUDES ACTION AND STUDY. IT RELIES ON INCENTIVES AND THE MARKET RATHER THAN MANDATES AND COMPLIANCE DEADLINES.

EVERY STEP WAS DIFFICULT. ALL REQUIRED BIPARTISAN POLITICAL EFFORT AND LEADERSHIP AS WELL AS COOPERATION AMONG INDUSTRIES.

ALTHOUGH THE PRESSURES FOR DRACONIAN ACTIONS MAY ABATE, THE ESTABLISHMENT OF NUMEROUS INTERNATIONAL AND DOMESTIC INSTITUTIONS, BUREAUCRACIES AND PROGRAMS WHICH EXIST SOLELY AS A RESULT OF THE ISSUE, ENSURE THE LIFE OF THIS ISSUE.

TO WIN THE FUTURE THE COAL INDUSTRY MUST CONTINUE TO INCREASE PRODUCTIVITY AND TO REMAIN THE COMPETITIVE FUEL OF CHOICE.

NEXT, THE MORE EFFICIENT TECHNOLOGY MUST BE DEPLOYED. THIS REQUIRES ENGAGEMENT WITH STATE AND FEDERAL REGULATORS AND POLICY MAKERS.

AND, MOST IMPORTANT, WE IN COAL AND ALLIED INDUSTRIES - THOSE WHO MOVE IT AND THOSE WHO USE IT -- MUST REMAIN DILIGENT IN TENDING OUR POLITICS.

AS A REPRESENTATIVE OF THE ENVIRONMENTAL DEFENSE FUND SAID ON DAVID BRINKLEY'S PRE-RIO SUNDAY SHOW, "THIS IS JUST THE FIRST ROUND."

THERE'LL BE MORE SCARE-STUDIES ON CLIMATE CHANGE AND MORE AGITATION FOR PUNITIVE LEGISLATION, BUT THE SCIENCE NOW IS RUNNING AGAINST THE AGITATORS.

SCIENCE HAS DETERMINED WITH OBSERVATIONS FROM SPACE THAT THE EARTH HAS NOT WARMED IN THE LAST 10 YEARS; FROM THE RECORD OF READINGS AT SEA THAT IT HAS NOT WARMED IN THE LAST 100; AND FROM U.S. RECORDS THAT, IN FACT, THERE HAS BEEN REGIONAL COOLING IN THE SOUTH.

NEVERTHELESS, STILL-CRUDE COMPUTER MODELS HAVE FORECAST A WARMING OUT ABOUT 2050. THEY CONCENTRATE ON CARBON DIOXIDE; ALL BUT IGNORE OTHER AND MUCH MORE POWERFUL SUSPECT GASES; AND ARE INCAPABLE OF HANDLING ALL THE COMPLEX WORKINGS AND INTERWORKINGS AFFECTING CLIMATE, WHICH ARE NOT ALL UNDERSTOOD. THE PROJECTIONS OF DIRE CONSEQUENCES ARE DRAWN FROM THESE COMPUTER FORECASTS.

RECENTLY THE CARBON DIOXIDE INFORMATION ANALYSIS CENTER AT OAK RIDGE NATIONAL LABORATORY PUBLISHED A STUDY THAT FOUND FACTORS OTHER THAN CARBON DIOXIDE MUST -- I REPEAT, MUST -- BE INVOLVED IN THE SLIGHT WARMING TREND DETECTED THIS CENTURY.

THE STUDY LOOKED AT RECORDED TEMPERATURES FOR MUCH OF THIS CENTURY FOR MOST OF THE WORLD'S NORTHERN HEMISPHERE -- AT THE U.S., AT RUSSIA AND AT CHINA. IT FOUND A PATTERN OF SLIGHTLY COOLER DAYS AND SLIGHTLY WARMER NIGHTS.

THE AUTHORS HAD TWO OTHER CONCLUSIONS -- POSSIBLY THE TRENDS HAVE LITTLE TO DO WITH HUMANS; AND THE TRENDS ARE BENEFICIAL FOR MOST HUMAN ACTIVITIES.

SCIENCE STILL CANNOT SAY IF THERE IS, OR WILL BE, WARMING; AND, IF THERE IS, OR WILL BE, WHAT THE CAUSES AND EFFECTS MIGHT BE.

THIS, THEN, IS A SKETCH OF COAL AND ENERGY TODAY.

THE 1990'S WILL BE A TIME IN WHICH AMERICANS RESOLVE THE SUM OF THEIR ASPIRATIONS -- THE BLEND OF ENVIRONMENTAL CONCERN AND ECONOMIC HOPE.

THEY KNOW WE CAN MAKE SUBSTANTIAL PROGRESS ON ECONOMIC AND POLITICAL PROBLEMS WITH TECHNOLOGY AND POLICIES THAT RAISE PRODUCTIVITY IN THE ECONOMY WHILE IMPROVING THE NATURAL ENVIRONMENT.

AFTER ALL, ONE POUND OF COAL IN 1990 DELIVERED THE POWER OUTPUT OF EIGHT IN 1890. AND EIGHTFOLD FEWER EMISSIONS.

THIS IS THE POWER OF TECHNOLOGY -- TO IMPROVE THE ECONOMY SO THAT PEOPLE MAY WORK AND WIN THE GOOD THINGS OF LIFE AND ALSO TO IMPROVE THE NATURAL ENVIRONMENT.

THE WELL-TOLD STORY OF THE ONCE AND FUTURE KING HAS PERTINENCE TO OUR TIME, AND TO OUR CONCERNS.

TOWARD THE END, T.H. WHITE HAD KING ARTHUR REFLECT ON WHY ALL THAT PROMISED GOOD HAD GONE BAD.

ARTHUR DETERMINED THAT:

> "SWEEPING REMEDIES COULD CUT OUT ANYTHING...AND LIFE WITH THE CUT. IDEAL ADVICE WAS NO ADVICE AT ALL.
>
> "WE CANNOT BUILD THE FUTURE BY AVENGING THE PAST."

THE FUTURE DOES NOT JUST HAPPEN: IT MUST BE ENABLED AND THEN BROUGHT ABOUT. IT COMES STEP-BY-STEP AND REQUIRES BALANCE AND TIMING.

WE KNOW -- WE HAVE PROVED TIME AND TIME AGAIN -- THAT TECHNOLOGY SOLVES PROBLEMS. JUST AS SOON AS PROBLEMS ARE UNDERSTOOD AND COMPREHENSIVELY DEFINED, TECHNOLOGY AND THE WIT OF MANKIND BEGIN TO DELIVER ANSWERS.

IN COAL WE HAVE AN ANSWER.

WE MUST BECOME MORE EFFICIENT AND SAFER IN PRODUCING IT. THE TECHNOLOGIES BEING DISCUSSED HERE WILL ADVANCE THIS OBJECTIVE.

AND WE MUST BECOME BETTER AT USING COAL.

IN THE COAL-COMBUSTION TECHNOLOGIES UNDER DISCUSSION HERE WE HAVE THE MEANS TO ADD BALANCE IN THE THREE GLOBAL ENVIRONMENTS CRITICAL TO SURVIVAL -- THE ECONOMIC, THE POLITICAL, THE NATURAL.

WE AT EITHER END OF THE COAL-CHAIN MUST BEGIN TO FIND WAYS TO JOIN IN COMMON CAUSE OR WE WILL FIND OURSELVES JOINED IN A COMMON END -- THE LINKED OBJECTS OF PUNITIVE ACTION IN A DECLINING WORLD.

THOSE WHO PRODUCE COAL AND THOSE WHO USE COAL MUST NOT NOW LET UP IN THEIR SUPPORT OF EXPANDED SCIENTIFIC STUDY OR OF EFFORTS TO DEAL WITH REASONABLE ENVIRONMENTAL CONCERNS IN PRODUCTIVE WAYS.

THERE IS GREAT OPPORTUNITY FOR EVERYONE IN THE COAL CHAIN -- FROM THOSE WHO PRODUCE IT TO THOSE WHO USE WHAT IT PRODUCES.

IF WE GET THE RIGHT PIECES IN THE RIGHT PLACES RIGHT NOW, WE TRULY WILL ENERGIZE AMERICA.

WE WILL DELIVER MUCH OF THE ENERGY TO DRIVE THE WORLD'S EVOLUTION TOWARDS ECONOMIC GROWTH AND PEACE IN A NEW ERA.

THE 1990's WILL BE A DECADE OF DECISION.

LET EACH OF US DO ALL WE CAN TO MAKE SURE THE DECISIONS ARE THE RIGHT ONES.

## THE CLEAN AIR MARKETPLACE

### The Clean Air Act: Spurring Innovation, Jobs, and Exports

### THE CLEAN AIR ACT AND THE CLEAN AIR MARKETPLACE

The Clean Air Act marked the beginning of a new era of environmental protection in the United States. This important piece of legislation directed the Environmental Protection Agency (EPA) to implement air pollution control regulations to ensure a cleaner and healthier environment for all Americans. In addition to fulfilling this mandate, EPA is striving to maximize the economic benefits that can be derived from the Clean Air Act to the U.S. economy. By turning its attention to important issues such as jobs, exports, and technology innovation, EPA is helping American businesses to enter the "clean air marketplace." Using flexible and innovative regulatory techniques and backing technological advances and new initiatives, EPA is supporting American businesses as they work toward meeting critical environmental goals in a cost-effective and energy-efficient manner.

Since the outset of the Clean Air Act, critics have argued that stark choices must be made between economic growth and further progress in air quality. However, by offering new solutions to formerly intractable problems, EPA has found that environmental objectives can be met while simultaneously fostering job and export opportunities. New markets and technologies stimulated by the provisions of the Amendments in air pollution control technology, emissions monitoring, and alternative energies are expected to bring significant economic growth and employment opportunities well into the next century. Environmental regulations abroad reinforce the demand for exports in these areas. Meanwhile, defense and other industries retooling for new markets can shift their physical and human resources to the environmental protection industry to retain jobs that might otherwise have been lost.

EPA is working to actively help promote innovation and business opportunities in the Clean Air Marketplace, and measurable results have already been achieved. However, EPA is aware that these opportunities are often accompanied by significant costs to American businesses that can impose hardships. It is important to keep these costs as low as possible. With this in mind, EPA has spent considerable time and attention examining the full range of economic impacts of the Clean Air Act and of air pollution control programs in general. High-priority attention has been given to addressing costs to regulated sources through regulatory impact analyses, plant closure studies, and cost benefit analyses. EPA has also made a concerted effort to identify ways of promoting, rather than impeding innovation. This has led to new initiatives, such as the "Green Lights" program, which has inspired several major companies to achieve cost and energy savings through EPA's voluntary energy-efficient lighting program.

Central to EPA's implementation strategy for the Clean Air Act has been its philosophy of building consensus among all stakeholders. EPA has made a point of going beyond standard rulemaking procedures to consult regularly with industry groups and to offer flexible regulatory regimes. EPA has also recognized the crucial role played by state and local governments, universities, and Federal agencies in achieving effective implementation of new rules while keeping costs to a minimum. Coordinated strategies have been built on the cornerstone of market-based approaches that can create "profits in the service of the environment."

## THE CLEAN AIR ACT AND THE ENVIRONMENT

The Clean Air Act was enacted to confront serious problems that pose a threat to public health and safety nationwide, at every level of society. Currently, over 100 urban areas in the United States do not meet health standards for ozone, carbon monoxide, and particulate matter. That's more than 140 million people still breathing polluted air. These pollutants cause health hazards that range from reproductive problems to respiratory infections, heart disease, and even lung damage. For example, in EPA's ongoing review of smog standards, studies were identified that show substantial reductions of lung capacity in previously health people resulting from ozone exposures. Acid rain poses risks to human health, as well as forests, lakes, streams, and national monuments. Toxic air emissions continue to create additional health hazards ranging from respiratory problems, to birth defects, to various forms of cancer. Higher up in the stratosphere, CFCs continue to deplete the Earth's delicate ozone layer -- a problem that has already begun to have impacts on people's lives: Children are no longer allowed to play outside during daylight hours in some parts of South America because excessive exposure to UV radiation is causing dramatic increases in levels of skin cancer.

The Clean Air Act will ensure that these problems are not passed on to future generations by:

- ☐ Removing 56 billion pounds of air pollution each year;
- ☐ Cutting toxic air emissions by more than 70%;
- ☐ Cutting acid rain-causing emissions by almost 50%;
- ☐ Eliminating CFC production by 1995; and
- ☐ Meeting health standards for nearly all areas by 2000.

The Clean Air Act will yield measurable and significant results: Cleaner air and a healthier environment for everyone. In real terms, this means a lot less urban smog, less heart, lung, and other disease, and more protection of valuable agricultural and natural resources.

## THE CLEAN AIR ACT AND THE ECONOMY

Although they are often posed as alternatives, clean air and economic growth can go hand-in-hand. Indeed, in countries around the world -- from the former Soviet Union to Mexico -- policymakers and business leaders are discovering that previous efforts to grow at the expense of the environment have created some of the biggest impediments to future growth. In fact, in its recent studies of economic impacts associated with the Clean Air Act EPA has identified a number of positive effects and economic opportunities:

- ☐ Growth in the environmental goods and services industry;
- ☐ New job opportunities for U.S. workers;

- New business opportunities for industries retooling for new markets; and

- Stimulus for technological innovation, cost savings, and exports.

EPA is committed to minimizing the significant costs that are also associated with the Clean Air Act -- $20 billion per year by the year 2005. As part of EPA's effort to keep these to a minimum, we have carefully examined Clean Air Act economic impacts in a number of studies, including regulatory impact analyses, plant closure studies, and business opportunities studies, (see appendix for more details).

Growth In The Environmental Goods and Services Industry

The conventional wisdom is that expenditures incurred by companies in complying with the Clean Air Act and other environmental laws constitute "lost" or sacrificed resources. EPA believes that this is the wrong way to think about environmental expenditures. Resources spent on environmental protection do not simply disappear. They go to firms in the fast growing environmental goods and services industry. These firms produce jobs, profits, and exports that fuel the clean air marketplace.

The market for environmental goods and services is large and is growing at a rapid pace. Environmental protection is already a $100 billion industry. A recent study conducted by ICF and Smith Barney Inc. projects that in the next three years, revenues in the air pollution control industry will jump by $4 to $6 billion annually and by $7 to $9 billion annually in the following five years for a cumulative increase of $50 to $70 billion over today's revenues by the year 2000. The Clean Air Act will spur even greater growth over the following two decades. These figures, in fact, are probably conservative, since the report dealt only with those opportunities that could be clearly identified and estimated. Additional revenue gains are probable as the demand created by the Clean Air Act ripples through the economy and affects many industries and companies that are not always considered to be a direct part of the air pollution control industry.

New Job Opportunities for U.S. Workers

Growth in the environmental industry means new jobs. These include both high-skill/high-wage and medium skill/medium-wage opportunities. In fact, the ICF/Smith Barney study shows that increased demand for employees in air pollution equipment manufacturing, on-site construction, design, and engineering alone could create up to 300,000 new jobs.

Examples of new jobs abound in a variety of fields, including energy conservation and renewable energy services, alternative transportation systems and other clean technologies, construction, and inspection and maintenance activities. A recent study by the Alliance to Save Energy, the American Gas Association and the Solar Energy Industries Association states that in an optimum scenario, energy production and service-related jobs could jump by 175,000 due to the Clean Air Act, and that jobs surrounding energy conservation services and renewable energy could increase by up to 190,000.

In the area of alternative transport systems technology and construction, California is leading the way: CALSTART, a new consortium of public and private sector firms in California, has launched an ambitious program focused on electric vehicle production and alternative transportation solutions. CALSTART could create up to 55,000 jobs in Los Angeles over a six-year period.

In Mont Belvieu, Texas, construction has just started on Sun-Enterprise-Mitchell's 12,500 barrel per day MTBE plant, creating both construction jobs for the local community and later new high skill jobs once operations begin in 1994. This is just one of approximately 60 new or expanded MTBE facilities under development. EPA also estimates that, as a result of the Clean Air Act, the U.S. economy could gain a net increase of up to 12,000 new U.S. jobs in vehicle testing and repair.

New Business Opportunities for Industries Retooling for New Markets

The Clean Air Act is not only creating entirely new job opportunities in relatively new or growing industries, but also creating opportunities for firms that are retooling for new markets. These opportunities can help preserve jobs that otherwise would have been lost as the defense and other industries "downsize." Companies with technological expertise and large, skilled workforces are well positioned to make this type of strategic shift.

Several firms have already begun to move in this direction. Defense contractors and aerospace firms, for example, can retool for activities such as production of electric vehicles or emissions monitoring equipment, which are discussed below. New civilian applications for space and defense technologies have already been discovered by leading firms. For example, the GM Sunraycer car is one of many new technological innovations in the clean air marketplace. GM/Hughes have used their technical expertise in advanced technologies such as photovoltaic cells, space vehicle materials, and aerodynamics to produce a state-of-the-art solar-powered vehicle. GM's Hughes Aircraft subsidiary played a large role in developing the Sunraycer. Additional adaptation of defense-related technologies such as high-tech monitoring and remote sensing are anticipated as the Clean Air Marketplace grows.

Growth in the clean air marketplace is reinforced by the growing market for green products. More and more Americans are considering the environmental impacts of the products they consume and green products are claiming ever increasing market shares in the United States. This trend reflects the fact that Americans, in poll after poll, identify themselves as environmentalists: In a 1990 Wall Street Journal/NBC poll, eight out of ten Americans polled said that they considered themselves environmentalists. In a 1991 Roper poll, 85% of Americans indicated that they are concerned about the environment.

American businesses are responding to these changing trends. According to the Food and Beverage Marketing service, green products accounted for 11.4% of all new products introduced in 1990, up from 1% in 1986. Moreover, a 1990 study of eighty major U.S. industrial corporations conducted by Deloitte & Touche and the Stanford Business School found that 31% had developed environmental marketing policies, 45% viewed environmental issues as "strategically critical," 20% had product "green labelling" programs, and 14% had introduced new "green" products. The study concluded: "...[C]onsumer and regulatory pressures are moving environmental issues to the heart of companies' financial and strategic plans."[1]

Stimulus for Technological Innovation, Cost Savings, and Exports

*Technological Innovation and Cost Savings.* New laws and regulations have been principal drivers in the development of new technologies in the environmental marketplace. Two types of cost-savings result from the stringency and flexibility built into the Act:

- Least-cost air pollution control; and
- Lower cost manufacturing as companies learn to operate "smarter."

Companies facing more demanding air pollution control requirements have been taking this opportunity to rethink how they make their products.

Historically, the development of new environmental technologies and the growth of the environmental marketplace have been driven most powerfully by new laws and regulations at the federal level. The Clean Air Act represents the most ambitious effort to use economic incentives and other market mechanisms to provide the flexibility necessary for maximum technical innovation. These market incentives harness "profits in the service of the environment." Among the principal innovation-inducing aspects of the Clean Air Act are the performance standards approach to setting toxic air pollution limits embodied in Title III, and the $SO_2$ allowance trading program established under Title IV. Acid rain provisions have already borne technological fruit: Scrubber manufacturers now guarantee 95% $SO_2$ removal, up from only 80% several years ago.

Tangible results in terms of cost savings have been achieved by American producers across several industries. The Kennecott Corporation, for example, plans to build a copper smelter that will be not only one of the cleanest, but also one of the lowest-cost and most efficient of its kind in the world. This enormous construction project will create 3,300 new jobs over three years, and more than 500 companies are expected to benefit from contracts to work on the smelter project. In Elmira, New York, an IBM plant recently redesigned a CFC-based electronic chip cleaning process, substituting environmentally friendly water-based cleansers for CFCs. By implementing a cleaner, more efficient process, IBM has saved $22 million. Along similar lines, a 3M Corporation project in Hutchinson, Minnesota is expected to yield savings of $5 to $7 million a year in solvent purchases by reusing toxic solvents.

*Export Advantages.* Air pollution control is a large and growing international industry: The 1991 world-wide air pollution control market totalled approximately $12 billion and tremendous growth is expected during the next decade in several key regions. The Asian

[1] In another survey, 89% of respondents were concerned about the environmental impact of their purchases and 72% said that a company's environmental reputation influences their product choice.

Development Bank predicts a fivefold to tenfold increase in air and water pollution in Asia due to an expected 300% increase in the number of vehicles and a 150%-200% expansion in industrial and mining activities. Taiwan, for example, is expected to spend up to $36 billion on pollution control over the next six years. South Korea expects to spend $2-3 billion a year on environmental clean-up. Eastern Europe offers longer-term market potential in air pollution control. U.S. companies compete against the Japanese, the Germans, and other Europeans for a share of this increasing market.

Technological innovation as a result of the Clean Air Act translates into an export edge for these U.S. companies in two ways. First, non-environmental companies can become tougher international competitors as they become "smarter" in response to Clean Air Act requirements. A leading experts on international competitiveness, Michael Porter of the Harvard Business School, has studied the international response of firms to more stringent pollution controls. Porter notes that "Strict environmental regulations do not inevitably hinder competitive advantage against foreign rivals; indeed, they often enhance it. Tough standards trigger innovation and upgrading." The Kennecott Corporation, mentioned above, is an example of this point. In fact, gains in energy efficiency, which often result from learning to be "smarter" producers, also give companies a cost and, therefore, a competitive edge over their counterparts in other countries. Looking overseas, we find that Japanese industry, which undertook a massive drive to increase energy efficiency in response to the 1970s oil shocks, today enjoys both cost advantages and lower pollution than their U.S. and European competitors.

Second, in the air pollution control industry, technical leadership paves the way for export leadership. For example, Joy Environmental Technologies Inc. (JET) and its German partner Gottfried Bischoff & Co., recently announced a $155 million contract with Taipower of Taiwan. The venture will install advanced wet scrubbers in a Taichung power plant that will reduce $SO_2$ more than 90%. JET expects to open a Taipai office this year.

## THE CLEAN AIR ACT AND ENERGY POLICY

### Reducing Oil Imports

The Clean Air Act supports U.S. national energy policy by reducing oil imports. Implementation of the Clean Air Act Amendments will reduce U.S. oil imports in at least two ways:

- ☐ Many new compliance technologies will also be more energy efficient, as companies try to operate "smarter" when it comes to energy and cost-savings. Gains in energy efficiency, which often result from learning to be "smarter" producers, also give companies a cost and, therefore, a competitive edge over their counterparts in other countries.

- ☐ The Title II oxygenate requirements will result in the replacement of fuel imports with MTBE and ETBE, which are derived from domestic gas and grain, respectively.

Economic Growth Does Not Require More Energy

Contrary to conventional wisdom, economic growth and growth in energy consumption are not directly correlated: Japan's economy, among the most fastest growing of the industrialized nations, is also the least energy-intensive. In fact, when Japan increased its energy efficiency in response to the 1970's world oil market shocks, it significantly reduced its level of air pollution at the same time. Now the Japanese economy derives more GNP from each BTU than the U.S. economy. Another way to view this comparison between Japan and the U.S. is that we generate much more pollution per dollar of GNP. The U.S. economy can grow while Americans work together to reduce the tons of pollution we emit into our environment every day.

## WHAT EPA IS DOING TO FOSTER THE CLEAN AIR MARKETPLACE

Technology Innovation and Exports

EPA is taking steps to improve its role as a technology advisor and leader by catalyzing efforts to develop and commercialize new technologies; disseminating information to industry; and responding to innovative entrepreneurs. EPA is supporting several new programs that are aimed at promoting U.S. exports and cultivating markets abroad for U.S. products. Several of our most important initiatives aimed at promoting innovation and exports include:

- **Green Lights**. Corporate America is embracing EPA's Green Lights Program, which invites companies to install energy-efficient lighting, reducing their lighting bills and cutting pollution. Companies sign an MOU with EPA, committing to install energy-efficient lighting throughout their facilities. In return, EPA provides a variety of technical assistance services to help make the changeover easier.

- **Golden Carrot**. In this EPA-sponsored contest, a group of refrigerator manufacturers have all contributed to a "pot" of money. The company that develops the most energy-efficient refrigerator wins the entire pot.

- **Energy Stars Computer Program**. EPA has announced the formation of voluntary partnerships with eight large computer makers to who are developing more energy-efficient computers that also cut air pollution.

- **NICE$^3$**. EPA and DOE are jointly funding the National Industrial Competitiveness through Efficiency: Energy, Environment, and Economics program. This pilot program provides funds to state agencies to improve industrial energy efficiency and reduce pollution.

- **NETAC**. NETAC is a non-profit corporation which received a start-up grant from EPA to link the resources and experience of industry, government and academia to help guide environmental technologies to the marketplace. Although EPA was a major donor in the first years, NETAC is now funded primarily from private sources.

- **The Environmental Training Institute**, a joint venture between the private sector and the U.S. government, has formed a cooperative network of public agencies and private companies help build capacity for environmental protection in developing countries. The USETI shares U.S. environmental advances with the international community by providing training courses in pollution control and waste management. By bringing foreign government and private officials to the U.S., and putting them in direct contact with U.S. firms, USETI helps build demand for U.S. pollution control exports.

- **The U.S.-Asia Environmental Partnership (US-AEP),** a coalition of American and Asian businesses, governments and community groups, set up with EPA participation, has designed four programs to focus U.S. expertise and resources on Asia's environmental and energy problems. These include training, exchange programs, and improving foreign access to U.S. technologies. U.S. companies will benefit from greater demand created for U.S. products and services that can help address Asia's environmental problems.

Support for State/Local Innovation

Another way EPA can build on new models of market-based approaches is to provide funding to state and local governments and universities. EPA has created a grant program to provide seed money to encourage states and local governments to develop, as part of their air quality plans, market-based incentives and other programs to spur innovation. To date, grants have gone to Illinois, several Northeastern jurisdictions, and Houston. The Air Emission Reduction Center (AERC), a new cooperative research center at the New Jersey Institute of Technology has been established to develop manufacturing technology with reduced emissions. AERC supports the notion that effective advanced pollution control can contribute to U.S. industry through innovation.

Consensus-Building

The philosophy at EPA for implementing the Clean Air Act is that all interested parties with a stake in clean air regulations should be involved in the process. EPA "Reg-Neg" roundtables and advisory committees have been successful in building consensus on many issues. For example:

- Regulatory negotiations for reformulated gasoline and equipment leaks standards helped to develop consensus and cooperation among industry, regulators, and other groups. For equipment leak standards, discussions led to a tighter standard based on an innovative enforcement scheme.

- Roundtable discussions on Navajo led to an agreement between the plant's owners and environmental groups to install more stringent control than EPA had proposed earlier.

- Roundtable discussions on early voluntary reductions of toxic air emissions led to a real regulatory reform by developing an innovative, flexible program, allowing industries to make maximum use of emissions trading to reduce the cost of emission reductions.

In short, what EPA has found -- time after time -- is that these innovative, consensus-based approaches receive strong support and can be effectively implemented.

## CONCLUSION

In sum, the Clean Air Act, together with EPA's flexible approach to implementing the law, represent both an environmental and an economic milestone. EPA is working hard to ensure a cleaner and healthier environment for all Americans, and to maximize the new economic benefits and opportunities created by the Act. Progress to date indicates that environmental and economic progress can go together, as efforts to clean the air create a vibrant, new clean air marketplace providing growth in the environmental goods and services industry, new opportunities for U.S. workers, new business opportunities for industries looking for new markets, and stimulus for technological innovation, cost savings, and exports. In addition, EPA is pursuing a number of other initiatives to promote energy efficiency and environmental technology innovation and exports. EPA is confident that these efforts, taken together, will yield cleaner air and a healthier economy as the U.S. steps up to the environmental and economic challenges ahead.

## APPENDIX

### EPA STUDIES: ECONOMIC IMPACTS OF THE CLEAN AIR ACT

- ***Costs to Regulated Sources:***

  Regulatory Impact Analyses
  *Plant Closure Study*
  Cost of Clean Air and Water
  Acid Rain Study
  *Section 811 Study on Trade*

- ***Health and Ecological Benefits:***

  Regulatory Impact Analyses
  *Acid Rain Study*
  Air Toxics Contingent Valuation Study

- **Pollution Control Sector:**

  Business Opportunities Study
  Clean Air Marketplace

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- **Section 812 Studies on Clean Air Act Costs and Benefits**

  Retrospective: 1970 - 1990

  Prospective: 1990 on

# PANEL SESSIONS

### STATE REGULATORY PANEL SESSION

*Moderator:* **The Honorable Ashley C. Brown**, Commissioner, Public Utilities Commission of Ohio
*Panel Members:* **The Honorable Daniel Wm. Fessler**, President, California Public Utilities Commission, **The Honorable Karl A. McDermott**, Commissioner, Illinois Commerce Commission, **The Honorable James R. Monk**, Chairman, Indiana Utility Regulatory Commission, **The Honorable Bil Tucker, Ph.D.**, Chairman, Wyoming Public Service Commission

### GOVERNMENT EXPORT PANEL SESSION

*Moderator:* **Peter J. Cover**, Program Manager, Coal Technology Exports, Office of Planning and Environment, U.S. Department of Energy's Office of Fossil Energy
*Panel Members:* **Dr. Robert A. Siegel**, Chief, Economic & Policy Analysis Division, Policy Directorate, U.S. Agency for International Development, **Dr. Joseph J. Yancik**, Director, Office of Energy, U.S. Department of Commerce, International Trade Administration, **John W. Wisniewski**, Vice President, Engineering, Export-Import Bank of the U.S. **Jack Williamson**, U.S. Trade and Development Program, **Harvey A. Himberg**, Director for Development Policy and Environmental Affairs, Overseas Private Investment Corporation.

### INDUSTRY EXPORT PANEL SESSION

*Moderator:* **Ben N. Yamagata**, Executive Director, Clean Coal Technology Coalition
*Panel Members:* **Anthony F. Armor**, Director, Fossil Power Plants Department, Electric Power Research Institute, **Robert D. McFarren**, Vice President, Stone and Webster International Corporation, **Dr. Charles J. Johnson**, Head Coal Project, East-West Center

### UTILITY PANEL DISCUSSIONS

*Moderator:* **Dr. George T. Preston**, Vice President, Generation and Storage Division, Electric Power Research Institute (EPRI)
*Panel Members:* **Dr. James J. Markowsky**, Senior Vice President and Chief Engineer, American Electric Power Service Corporation, **Stephen C. Jenkins**, Senior Vice President, Commercial Development, Destec Energy, Inc., **Randall E. Rush**, Director, Clean Air Act Compliance, Southern Company Services, Inc., **George P. Green**, Manager, Electric Supply Resources, Public Service Company of Colorado, **Howard C. Couch**, Manager, Environmental and Special Projects Department, Ohio Edison Company

# BIOGRAPHIES OF PANEL MODERATORS

**The Honorable Ashley C. Brown** *STATE REGULATORY PANEL SESSION*
Mr. Brown serves as the Commissioner of the Public Utilities Commission of Ohio. He was appointed to the Public Utilities Commission of Ohio by Governor Richard F. Celeste on April 11, 1983, for a term ending April 10, 1988. He was reappointed to a second term on February 24, 1988, for a term ending April 10, 1993.

**Peter J. Cover** *GOVERNMENT EXPORT PANEL SESSION*
As Program Manager, Coal Technology Exports, Mr. Cover is responsible for managing the U.S. Department of Energy's Office of Fossil Energy's Coal and Technology Export Program. This program supports and promotes the export of U.S. coal and coal technologies. The program is a cooperative effort with U.S. industry and other U.S. Government agencies with the objective of increasing international trade opportunities for U.S. coal and clean coal technologies.

**Ben N. Yamagata** *INDUSTRY EXPORT PANEL SESSION*
Mr. Yamagata is the Executive Director of the Clean Coal Technology Coalition. His legal practice encompasses federal and state legislative issues that deal with energy, environment, natural resources, international trade (technology transfer) and transportation-related matters. Special expertise includes representation before the legislative branch with respect to federal appropriations and energy-related tax issues as well as matters before Congressional committees with jurisdiction over energy, environment, natural resources and transportation matters. He has advised the $2.7 billion Department of Energy clean coal technology development program. Mr. Yamagata is Executive Director of the Clean Coal Technology Coalition and counsel to the Electric Transportation Coalition.

**Dr. George T. Preston** *UTILITY PANEL DISCUSSIONS*
Dr. Preston joined the Electric Power Research Institute (EPRI) in 1978 as Program Manager, Desulfurization Processes, moving to Director, Environmental Control Systems in 1981 and Director, Fossil Power Plants in 1984. In January 1991 he became Vice President, Generation and Storage Division. Dr. Preston was instrumental in establishing EPRI's first subsidiary, CQ, Inc., and is Chairman of its Board of Directors.

# STATE REGULATORY PANEL SESSION

The State Regulatory Panel will discuss: Regulatory incentives for demonstrating and deploying advanced electric power technologies; Energy implications of the valuation of environmental externalities; Implications of the Clean Air Act Amendments of 1990 on coal-based electric capacity planning; and Emission allowance trading.

Moderator:

**The Honorable Ashley C. Brown**, Commissioner, Public Utilities Commission of Ohio

*Mr. Brown serves as the Commissioner of the Public Utilities Commission of Ohio. He was appointed to the Public Utilities Commission of Ohio by Governor Richard F. Celeste on April 11, 1983, for a term ending April 10, 1988. He was reappointed to a second term on February 24, 1988, for a term ending April 10, 1993.*

Panel Members:

**The Honorable Daniel Wm. Fessler**, President, California Public Utilities Commission

**The Honorable Karl A. McDermott**, Commissioner, Illinois Commerce Commission

**The Honorable James R. Monk**, Chairman, Indiana Utility Regulatory Commission

**The Honorable Bil Tucker, Ph.D.**, Chairman, Wyoming Public Service Commission

Remarks of

**Daniel Wm. Fessler**

President, California Public Utilities Commission

Before

**THE DEPARTMENT OF ENERGY CLEAN COAL TECHNOLOGY CONFERENCE**

Cleveland, Ohio
September 22 - 24, 1992

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I am grateful to Secretary Siegel for the invitation to join your deliberations and particularly appreciate the opportunity to be associated with my colleague, Ashley Brown, whose writings and work I have come to admire. And I would say to my colleague from Wyoming, Commissioner Tucker, that I believe his assault upon what I take it to be the recent work of the Oregon Commission to be a tad shrill. It is evident that I am a stranger in your midst, and before I sit down I shall have confirmed your suspicion that I am no expert in this field. In truth, I am a school teacher, summoned from a classroom at the University of California by Governor Wilson. For the past twenty months I have been engaged in the multi-faceted issues surrounding the acquisition and distribution of energy for the thirty-five million Californians. I am here to recount some of our struggles, to speak with becoming modesty of some of my Commission's accomplishments, and to learn from you.

**The Commission's Role in Electric Resource Planning**

The California Public Utilities Commission's regulatory role in electric resource planning has changed dramatically over the past fourteen years. These changes began in 1978, when passage of the Public Utilities Regulatory Policies Act firmly acknowledged that the generation of electricity is not a monopoly function and that society would benefit from the participation of a non-utility generation sector.

In that yesterdecade, California relied on oil and natural gas for more than 50 percent of its electric power generation. Today, California has one of the world's most diverse resource mixes for electricity generation. In 1989, 52 percent of the actual electrical energy supplied came from non-fossil fuels. California also leads the nation in the amount of electricity supplied by non-utility generators. By 1994, qualifying facilities will provide 8,774 MW of dependable capacity to my state.

**Competition**

Since the passage of PURPA, the Commission on which I am privileged to serve has consistently demonstrated its commitment toward establishing a fully competitive market in electric generation. The most noteworthy product of the Commission's efforts to date is our much debated Biennial Resource Plan Update. We created the Update to facilitate reliable, least-cost, environmentally-sensitive electric service through a systematic analysis of the utilities' need for new resources and options to meet that need.

There are three main aspects of the Update which arise in the context of a collaborative rather than a command and control setting. We first seek to identify the need for new generation capacity for each of the three large electric utilities in California. At step two we determine what portion of that need can be supplied by the utilities or Qualifying Facilities (QFs). Finally, we have the task to establish reasonable prices and contract terms for the utilities' purchase of that capacity and energy supplied by QFs.

The Commission's long-term goal in the Update is to establish a process by which California can achieve the most efficient, environmentally-sensitive, least-cost resource mix and a fully competitive electric generation market. The history of the Update reveals the Commission's efforts toward achieving the first half of its long-term goal, while the broader objective of full competition is the primary focus of related Commission investigations into Electric Transmission Access and All-Source Demand and Supply Side Bidding.

As I just noted, the second half of the Commission's long-term goal, the creation of full competition, is addressed in two related proceedings. On Wednesday of last week we took two significant steps. We concluded one of the most rewarding and broadly cast collaborative exercises by announcing the terms of an interim policy on Electric Transmission Access. Our purpose is to assure that QFs will have the ability to utilize and/or construct the transmission facilities necessary to connect their facilities with the purchasing utility. We have sought to design a transparent system wherein the bidding process can be informed by accurate and timely information. The system is now in place and will be used in the long-awaited auction.

On the same day that we adopted the interim policy on transmission access, we modified the Update decision to allow Southern California Edison to revise its cost figures for the identified deferrable resource. Our permission is conditioned on Edison's unconditional commitment to build out the repower at not one cent more than the quoted price and performance terms if no Qualified Facility is able to beat these revised figures. While both interim and experimental, the avowed goal of this move is to place utility and non-utility generators on a level playing field subject to the same rules.

I should also mention that the Commission is also currently examining whether the benefits of competition can be realized in the DSM arena. We are looking at bidding by third parties to pursue DSM measures. The intent is to introduce competition to DSM services.

**Valuing Environmental Externalities**

The Commission has consistently supported the use of increased energy efficiency and cleaner technology in meeting California's electricity needs. We realize that the utility sector is only one of the many contributors to the state's air quality problems. While we are committed to improving the air quality of the state, we are keenly aware that we should not ignore traditional cost-effectiveness analysis in pursuit of our environmental objectives.

By legislative mandate, the Commission is directed to include a value for any costs and benefits to the environment in calculating the cost effectiveness of energy resources. The Public Utilities Code further specifies that until such time as the Commission adopts a monetary value for fuel diversity, the Commission shall set aside a portion of new generating capacity for renewable resources.

In an attempt to balance the risks that incorporating such societal and environmental concerns places on the state's ratepayers, we have directed that non-uniform residual emission values be included in utilities' cost-effectiveness analysis of resource options. The value of residual emissions is tied to the attainment or non-attainment status of the point of production.

Emissions generated in non-attainment areas (areas in which emissions levels exceed acceptable standard criteria) are valued using the purchasing utility's marginal cost of controlling the regulated pollutants. Emissions produced by sources in attainment areas are assigned values adopted by the Nevada Public Service Commission.

The adopted residual emission values are incorporated into the resource procurement process in two phases: planning and acquisition. In the planning phase, the utility is required to include the imputed emission costs from power plant operation in the cost-effectiveness analysis. During the acquisition phase, the value of emissions is incorporated into the bidding protocol and the payment provisions. QF bidders will receive payment adders or subtractors if they are "cleaner" or "dirtier" than the utility's identified deferrable resource.

We area aware that state policy to directly incorporate environmental costs is a drastic change. In adopting this new course we recognize that it is desirable to send strong, and clear pricing signals to both utility and independent power producers. At the same time, we must recognize a need for a period of transition. This last point explains our decision to exempt short-term power purchases from the application of emission adders. In short, we believe the recent Update decision results in a fuel neutral resource procurement policy for the state.

**Clean Air Act Amendments**

The Clean Air Act Amendments of 1990 introduced additional requirements for public utilities. This legislation has served to strengthen and support our commitment towards environmentally sensitive resource planning. The Amendments require public utilities to reduce emissions of sulfur dioxide ($SO^2$) and nitrogen oxide ($NO_x$) in order to mitigate the effects of acid rain. It is believed that utilities nationwide account for 80% of $SO^2$ emissions and 30% of $NO_x$ emissions. The legislation also is intended to promote energy conservation and the use of renewable energy resources. In concert with our own longer standing policies, the Amendments identify renewable resources as those which utilize biomass, geothermal, solar, or wind generation.

The $SO^2$ reduction program includes the use of tradeable emissions allowances which authorize and thereby limit specific amounts of $SO^2$ emissions. The EPA will issue power plants a prescribed number of emissions allowances. A utility will be restricted to emitting from a plant only as many tons of $SO^2$ as correspond with the number of allowances it possesses for that plant. By lowering the emission levels of a plant, a utility can free-up allowances which can be sold or traded on the open market.

The $SO^2$ reduction program is divided into two phases. California utilities will not be obligated to meet emissions limits, or eligible for emissions allowances until Phase Two, beginning in the year 2000. In phase two, California's initial endowment of allowances will exceed current emissions in the state by 20 percent, due to the state's existing energy efficiency and renewable technologies.

In addition to the prescribed allowances, the utilities—and all other emitters covered by the recent Amendments—can receive additional allowances by increasing investments in energy efficiency measures renewable technologies. Renewable generation use or purchases are limited to those units that were not operational before January 1, 1992.

**Research, Development and Demonstration**

The Commission believes that effective use of utility research, development, and demonstration is critical for California. We believe that successful RD&D programs should reduce a utility's costs, reduce rates to customers, and improve the utility's ability to contend in the increasingly competitive electric generation environment.

The Commission currently authorizes the utilities to conduct RD&D programs through traditional ratemaking methodology. We allow the inclusion of RD&D expenses in determining rates, enabling the utility to recover the costs of the programs. Individual program budgets are subject to review in the utility's General Rate Cases.

The Commission seeks to encourage cost-effective utility RD&D, and is investigating alternatives to traditional cost-of-service based regulation in order to effectively stimulate increased utility investment in RD&D. We are actively considering implementing RD&D commercialization incentives to encourage the development of innovative technology. We strongly believe that such innovation is the key to California's continuing energy success. We have asked utilities to explore alternative means of developing utility incentive mechanisms for RD&D program innovation and increase the priority for commercialization of RD&D projects.

**Coal Gasification Project**

One such demonstration project was developed by Edison and Texaco at Edison's Cool Water Generating Station using Texaco's Coal Gasification technology. The project was designed to reduce the state's reliance on oil, provide diversity, and produce a reliable energy resource. In 1989, the project ended its original five-year demonstration run. Cool Water successfully demonstrated Texaco's Coal Gasification technology, but the project did not prove cost-effective for Edison's ratepayers. The high capital cost of this coal-based technology more than offset any environmental benefits.

The Commission granted Edison permission to recover in rates the reasonable excess expenses related to its operation of Cool Water as a demonstration project from 1984 to 1989. The decision also adopted a Joint Recommendation signed by Edison and the Commission's Division of Ratepayer Advocates that requires review and preapproval of any negotiated purchased power proposal concluded between Edison and Texaco.

In 1991, Texaco petitioned to have the project's certification extended, based upon the incorporation of the gasification of sewage sludge, the production of methanol or alcohols, and other refinements. The modified facility has been certified as a QF by the Federal Energy Regulatory Commission and as a demonstration project by the California Energy Commission. Our state Energy Commission's siting decision is significant, for it determines such issues as whether a project (1) qualifies as a demonstration project and (2) has justified the projects costs, by providing both energy and environmental benefits. Yet the determination is not dispositive, for the burden of weighing the costs against the benefits to ratepayers is the singular responsibility of my Commission.

Edison and Texaco are negotiating to transfer the Cool Water facility to Texaco, however, the sale is contingent upon Edison and Texaco signing a purchased power agreement. Edison has offered Texaco a Standard Offer 1 contract, which Texaco has rejected since it needs significantly greater revenues for Cool Water to be economically viable.

My Commission believes that Texaco should be compensated for Cool Water's power at a rate that best reflects what it would cost Edison to operate Cool Water. Any amount paid above and beyond Edison's current cost of power is the cost of continuing to demonstrate Cool Water's technology, technology that is not yet cost-effective in California in the context of an investor owned utility and should not be subsidized by Edison's ratepayers.

The Commission is charged with establishing just and reasonable rates for electric service and will ultimately decide whether ratepayers should pay anything greater than the cost of Cool Water's power. We believe that past decisions regarding nonstandard contracts and on utility/QF negotiations give adequate guidance for demonstration project sponsors such as Texaco. The Commission stated in an earlier decision that the Update is not the appropriate forum for addressing demonstration projects, nor is it the appropriate forum for determining the value to ratepayers of demonstration projects.

Texaco has asserted that the power purchase agreement price should be higher than the current market price, due to the demonstration value of the plant. This position is vigorously opposed by our Division of Ratepayer Advocates. The Division points to California's current excess generating capacity, relatively low fuel costs, and complete lack of coal. The ongoing value of the demonstration project is questioned given the fact that coal gasification is an established technology that Texaco has licensed in other plants worldwide. The intended impact of these arguments is that the demonstration value of the project is not significant enough to offset the increased cost. Therefore, the Division does not support signing a power purchase agreement at any price above market value. The prevailing prices in the Commission's Standard Offer 1, the only offer that is currently available, and final Standard Offer 4, when approved and used for the upcoming auction, should be the price paid for power.

Texaco contends that the existing standard offers are not suitable for demonstration projects. The belief is that the Commission, in addition to utility RD&D, should provide nonstandard contracts with adequate payment mechanisms to provide incentive for demonstration projects. Standard Offers are more appropriately used for established technologies.

The most appropriate options available to Texaco at this time are:

- Edison and Texaco can sign a nonstandard purchased power agreement. This option seems the most appropriate given the past Commission decisions regarding nonstandard projects.
- Texaco and Edison could also sign a Standard Offer 1 (variable capacity and energy) contract.
- Another option available is entering the upcoming Standard Offer 4 auction process by submitting a bid. Since Cool Water has been designated as a demonstration project by the CEC, the project will not be counted against need should it's bid prevail in the auction.
- Alternatively, Texaco could be granted an exemption from participating in the auction and simply receive the prevailing second price auction bid price.

## CONCLUSION

In summary, I to thank you for the opportunity to participate in this discussion. In California we are committed to encouraging new, innovative research, development, and demonstration projects both through utility programs and by creating additional opportunities for non-utility power producers to enter the electric generation market. I strongly urge your continued search for technologies which will allow the use of coal as a major fuel in the production of electricity. I recognize the vast energy potential of coal and, as a representative of thirty-two million consumers of electricity, we are not shutting the door on any competitor for our business. I would commend to you the text of remarks I offered to your colleagues in the gas industry at a recent gathering in New Mexico. My theme was quite simple. In California we are willing to explore partnership opportunities with anyone. We seek no special terms and we are determined to resist any attempt to discriminate against us. In short we are willing to become the partner of any progressive industry just as we are determined to be no one's patsy.

# INCENTIVE MECHANISMS AS A STRATEGIC OPTION FOR INNOVATIVE TECHNOLOGY DEPLOYMENT

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First Annual Clean Coal Technology Conference

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"Technical change is like God. It is much discussed, worshipped by some, rejected by others, but little understood."

...Ross Thomson
Economic Historian

# WHY ARE INCENTIVES BEING CONSIDERED

- Changing economic conditions
- Changing market structures
- Changing technological conditions
- Public goods nature of information
- Evolving philosophy on the role of regulation
- Economic and technological risks
- Environment policy changes

# PROBLEMS CONFRONTING NEW TECHNOLOGIES

- Improving existing technologies is perceived as safer
- Public goods and externalities associated with technology development
- Uncertainties concerning cost, reliability and lead times

# WE HAVE A CHOICE TODAY: IT IS REALLY A CHOICE OF INSTITUTIONAL ALTERNATIVES

- We can let competition provide the solution, or

- We can adapt our current regulatory methods

Which of these minimizes the cost to society?

When competing technologies are being adopted sequentially, if there is uncertainty about the relative merits of the competitors, the market will under supply experimentation. There is no incentive for an adopter to experiment with what appears to be an inferior technology in hope of improving the estimate of its merit.

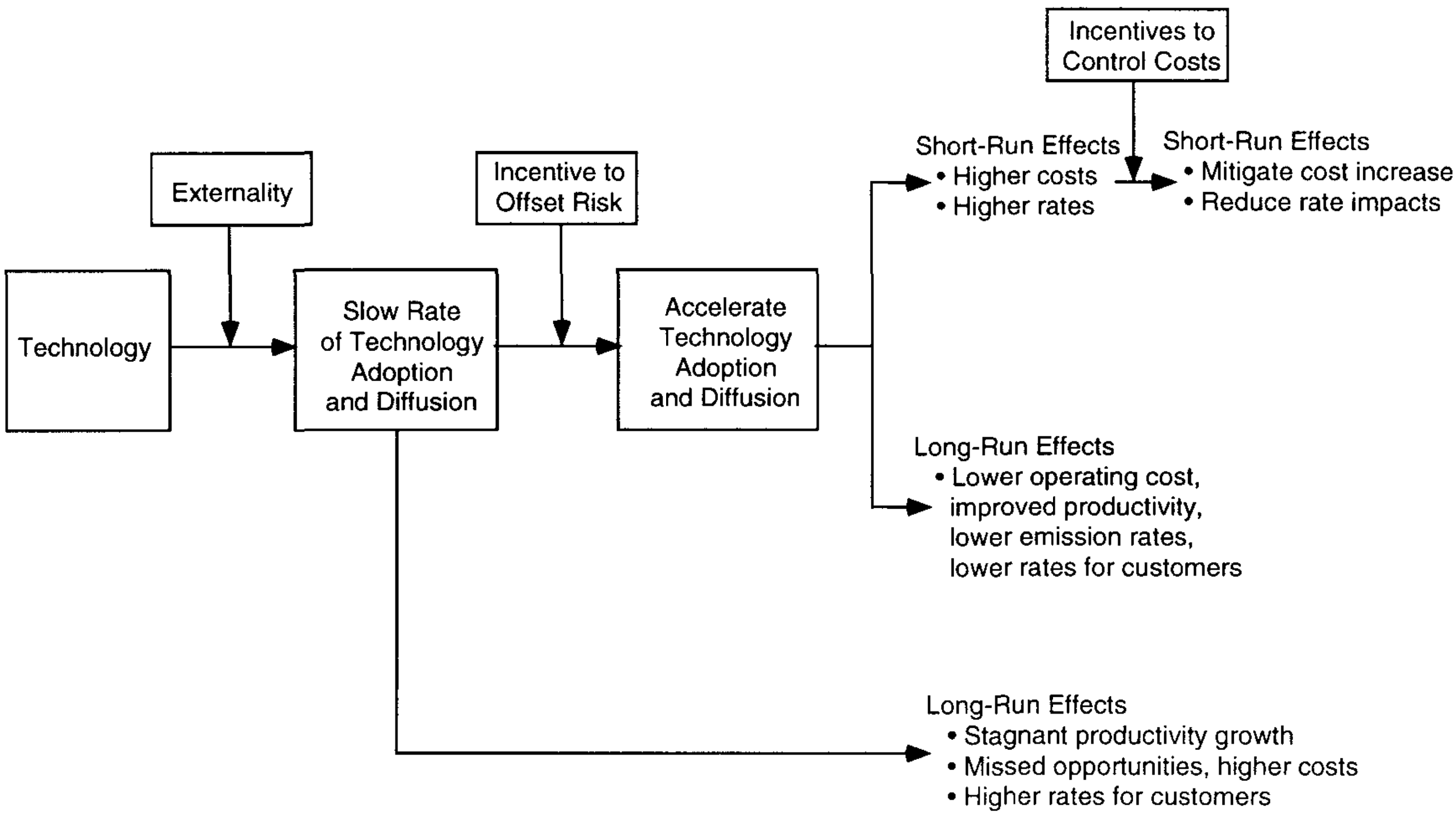
# DUAL INCENTIVE PROBLEM

- How to offset the inherent risks associated with a new technology
- How to design an incentive that will encourage the control of a project's cost

"regulation as such contains no built in mechanism for assuring efficiency. To the extent that it effectively restrains public utility companies from fully exploiting their potential monopoly power, it tends to take away any supernormal returns they might earn as a result of improvement in efficiency, thereby diminishing their incentive to try."

A. Kahn
"The Economics of Regulation" (1970)

# SUMMARY OF TECHNOLOGY ADOPTION AND EFFECTS OF INCENTIVES



## WHAT ARE INCENTIVES?

- Mechanisms designed to alter behavior in order to achieve a specific goal
- Goals can be: improved performance, offset excessive risk, improve quality of service, etc.
- Mechanism can involve rewards, penalties or both

# MISPERCEPTIONS REGARDING INCENTIVES

- Additional awards for standard operations
- Providing utilities monopoly profits
- Distortions of the market

# WHAT ARE THE BASIC TYPES OF INCENTIVE MECHANISMS?

- Automatic rate adjustment
- Incentive rate of return or sliding scale mechanisms
- Cost and shared saving mechanisms
- Yardstick - comparative performance
- Price caps

# REGULATORS HAVE EMPLOYED INCENTIVE MECHANISMS

- Regulatory lag
- Zone-of-reasonableness in the rate-of-return
- Prudency/used and useful tests
- Fuel cost
- Construction cost
- Plant performance

# CONCLUSIONS

- Economic, technical and environmental changes have created forces that threaten to mute the performance incentives facing utilities

- Regulators have at their command a wide range of incentive mechanisms that can be used to enhance existing incentives or create new incentives designed to improve utility performance

# INCENTIVE MECHANISMS AS A STRATEGIC OPTION FOR INNOVATIVE TECHNOLOGY DEPLOYMENT AND ACID RAIN COMPLIANCE[•]

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* Commissioner, Illinois Commerce Commission.

• Previously presented at: *The Future of Incentive Regulation in the Electric Utility Industry*, PSI Energy and School of Public and Environmental Affairs/University of Indiana, Indianapolis, Indiana, November 18, 1991.

**Incentive Mechanisms As A Strategic Option For Acid Rain Compliance**

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## 1 INTRODUCTION

Title IV of the Clean Air Act Amendments (CAAA) of 1990 (P.L. 101-549) establishes the use of flexible emission compliance strategies for electric utilities to reduce the emissions of acid precursors ($SO_2$, $NO_x$). To control $SO_2$ emissions, tradeable emission allowances will be used; $NO_x$ emissions will be controlled by an emission standard, but a utility is permitted to average $NO_x$ emissions systemwide to meet the standard. Both of these policies promote flexibility and cost savings for the utility while achieving the prescribed emission reduction goals of P.L. 101-549.

The use of $SO_2$ emission allowances has two notable benefits (other than the projected reduction in acid deposition) first — a utility has the choice of a wide range of compliance methods allowing it to minimize compliance costs and second, the use of transferable emission allowances promote technological innovation with respect to emissions reduction/control.[1]

The traditional means of pollution control has been through technology requirements, uniform emission standards and site-specific standards (McDermott and South, 1990). None of these options allow a utility or system of utilities (e.g., power pool) to truly minimize the costs of pollution compliance. Through the market mechanism of a tradeable allowance, compliance costs can be minimized by allowing utilities to take advantage of interfirm control cost differences. In addition, traditional regulation has provided little incentive for

[1] See Hahn and Noll (1982) for a discussion on different means of implementing allowance trading programs and the theoretical outcomes. For a discussion of technological innovation and the use of environmental policy instruments, see Milliman and Prince (1990).

technology innovation due to the relatively low rewards and uncertain acceptance of the technology. The use of allowances give greater rewards to the innovating firm for reduced emissions in the form of allowances freed for other uses. The use of incentive- or market-based regulation for the control of pollution generates two important outcomes:

1. The market may not achieve the desired outcomes of compliance cost minimization, technological innovation and reduction in acid deposition. State regulations, price/quantity uncertainty in the allowances market, and other forces may cause the market to under-perform leading to greater compliance costs and less technological innovation. In this case, regulatory incentives may play a potential role in augmenting the market incentives (embodied in Title IV, P.L. 101-549) and encourage technological development and compliance cost minimization.
2. The use of emission allowances and command and control (CAC) emission regulation is analogous to the use of regulatory incentives and traditional rate-of-return regulation for public utilities. Incentive regulation or incentive mechanisms (such as emission allowances) give the targeted firms rewards for such actions as minimizing operation (or compliance) costs and encouraging the development of innovative generating (emission control) technologies.[2] When traditional regulation fails to provide sufficient incentives for cost minimization or cost saving innovations, incentive regulation may be applicable for the achievement of these goals in the public utility industry.

[2] Note that emission control technology and electricity generating technologies are not mutually exclusive. Renewable technologies such as solar, photovoltaic, hydro, wind, and geothermal, clean coal technologies (CCTs), and second generation nuclear plants all generate much less pollution (or negative production externalities) while lowering the incremental cost of electricity.

This paper will examine how regulatory incentives can aid in the achievement of a Title IV goal: cost-effective reduction of $SO_2$ emissions. In addition, the ability of regulatory incentives to encourage the development of clean, electricity generating technologies will be examined. Section 2 of the paper will describe why incentives are adopted, and present a synopsis of the historic adoption of incentives. In Section 3, desirable properties of regulatory incentives are outlined along with how to evaluate the success of regulatory incentives. Section 4 delves into the issue of regulatory incentives for deploying/adopting innovative electricity generating technologies to help meet the goals of the CAAA of 1990. To conclude, Section 5 indicates the possible benefits of a well-functioning allowance market and the use of incentive regulation to achieve the goals of improved air quality and cost-effective compliance with Title IV of the CAAA of 1990.

## 2 INCENTIVE REGULATION: ADOPTION AND HISTORY

Traditional regulation of the electric utility industry has typically been concerned with reliability of service, and established tariffs so that a utility's total costs are compensated. Also, a rate of return is specified for a utility's capital expenditures in order to attract the necessary financial capital. During the decades of the 1950s and 1960s, the electric utility industry took advantage of increasing returns to scale as demand grew. This resulted in continually declining rates, increased shareholder returns on equity, and satisfied customers. Cost-plus regulation worked fairly well during a relatively stable period of demand growth and low inflation.

During the 1970s, however, a series of supply shocks, many plant cost overruns, and declining demand resulted in an increase in the price of electricity. In response, state public utility commissions (PUCs) reacted by initiating retrospective prudency review, disallowances of capital costs, and excluding abandoned construction (even partially) in ratebase. These actions placed the utility industry in serious financial jeopardy as earned rates of return fell and prices rose (Seretakis, South and Rogers, 1988).

To cope with the problem of increasing construction costs, the belief that utilities were failing to operate in a least cost manner (i.e., gold-plating or x-inefficiency) and increasing electricity rates, two important solution were proposed. First — the use of incentive mechanisms — was based on the theory that the utility, given "cost-plus" regulation, has little incentive to minimize costs and in fact may attempt to increase costs to generate greater profits.[3] The second idea — the introduction of competitive forces — was to take advantage of new technologies associated with the cogeneration of process steam and electricity under the Public Utility Regulatory Procedures Act (PURPA) of 1978. PURPA would require a utility to purchase excess electricity from a cogenerator at the utility's avoided cost. In this way, the ratepayers would not bear the risk of utility plant construction and would potentially receive lower electricity prices.

But before we delve into the actual state and federal programs using incentive regulation it may be useful to consider why incentives are adopted and examine some misconceptions about incentive regulation.

## 2.1 Adopting Regulatory Incentives

As can be surmised from the experience of the 1970s, incentives have been considered as an alternative means of regulation because of the failure of traditional regulation to cope with a rapidly changing industry and world.[4] The chief failure of traditional regulation has been in terms of *not* encouraging the efficient production of

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[3] See Averach and Johnson (1962), Kahn (1970), and Joskow and Schalmensee (1986) for the tip of voluminous literature on incentive regulation.

[4] This statement is not meant to imply that tradition regulation has been a complete failure. Traditional regulation has done a fine job in ensuring reliability and "fairness", but lacks the necessary mechanisms to ensure the efficient production of electricity. It is an encouraging sign that over the years regulators have adopted numerous mechanisms designed to enhance the traditional regulatory incentives to encourage efficiency.

electricity given the changing economic environment. Many sources have indicated that tradition regulation fails to assure efficiency in production as indicated by Kahn (1970):

> *regulation as such contains no built in mechanism for assuring efficiency. To the extent that it effectively restrains public utility companies from fully exploiting their monopoly power, it tends to take away any supernormal return they might earn as a result of improvement in efficiency, thereby diminishing their incentive to try.*

The changes in the structure of regulatory and technological risk, as well as the increase in environmental regulation and the change in the philosophy of regulation towards deregulation, imply the need to explore alternative means of regulating the utility industry. The structure of technological and regulatory risk has been altered due to the asymmetry in the reward and penalty structure of current regulatory procedures. If the utility adopts an innovative technology and reduces costs these savings are passed onto ratepayers, while an innovative action taken by the utility which fails results in the shareholders assuming all its burden. Moreover, the use of ex post prudency reviews for new construction projects, originally considered to have been prudent, has led to higher capital costs paid by customers as financial markets react to the increased perceived risk. In addition, environmental regulation has resulted in higher electricity rates with the use of inefficient rollback and technology standards that do not promote efficiency. Finally, traditional regulation has not allowed utilities to compete effectively in the more workably competitive market created by PURPA. Utilities find it difficult to respond to competition by reducing tariffs to the incremental cost of service for one group (industrials) in order to minimize rate increases for other classes of customers (e.g., residential, commercial).

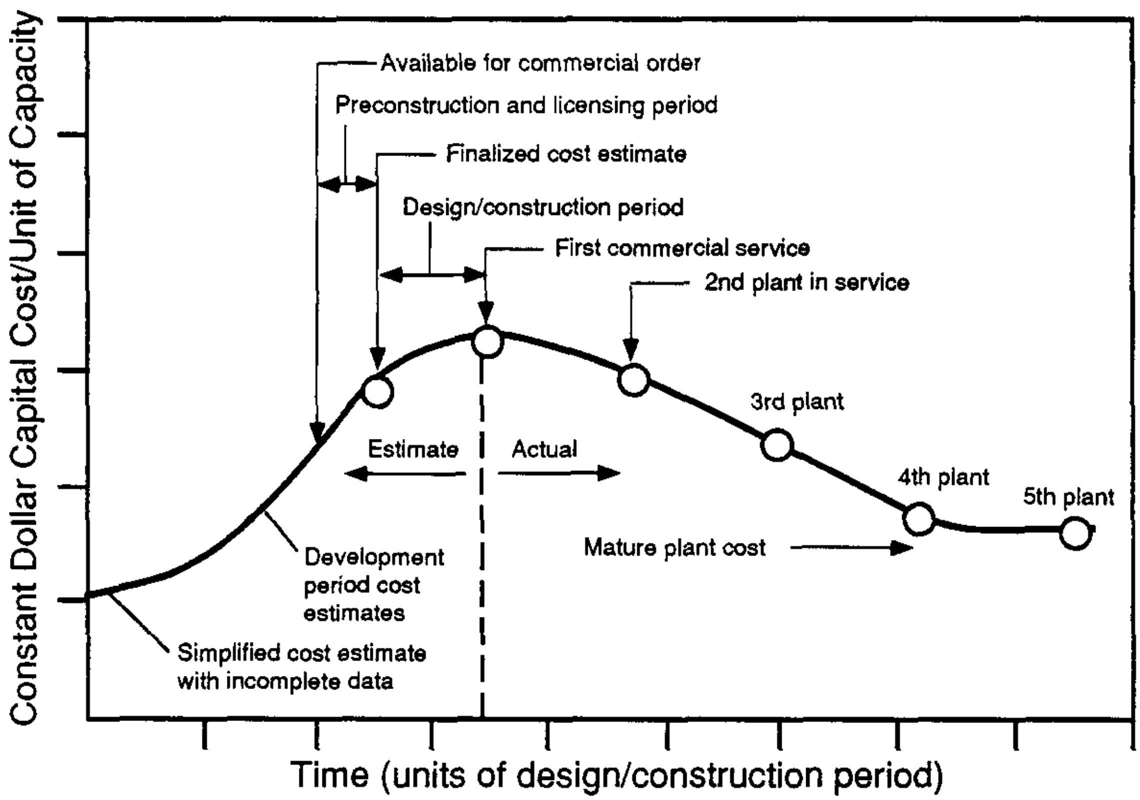
Incentive regulation is designed to improve efficiency, rather than as some perceive of merely rewarding the monopoly power of a utility through additional profits. Incentive regulation attempts to provide rewards (penalties) for operations and construction which are efficient (inefficient). Those firms maintaining a business-as-usual approach to operations will not receive the benefits of the incentive and may in fact incur some penalties. The incentive is designed to provide temporary profit from cost-reducing actions that will then be translated into lower rates for customers over time. The incentive mechanism simply applies standard economic motivations that recognize that a firm will not undertake an action unless the marginal benefit (profit) it receives is greater than the marginal cost of the action. If the actions taken are irreversible, the benefits to customers are permanent since the cost reductions are passed-through to rates.

In the history of incentive regulation, three general cases of their use can be identified: (1) to establish parity between different activities; (2) to compensate for technological risk and the public goods aspect of information; and (3) to control operating and construction costs. The most relevant case associated with creating parity can be seen in the utility choice between implementing a supply-side option, such as new power plant to meet load growth, or using demand-side management (DSM) to reduce load growth to that equivalent with existing capacity. Why would their be a difference between the two options in terms of utility choice?

Under traditional regulation, capital expenditures receive a return through rate base, and operating and other variable expenses receive a direct passthrough to rates. The utility's tariffs are based in part on the need to cover these expenses. The utility generates revenues to cover expenses through the sale of electricity. Any program, such as DSM, which reduces sales, and thus reduces revenue and results in lower profits, will not be implemented. If a new plant is built to meet increased load requirements, it can be expensed through rate base and thereby be incorporated into customer rates, resulting in continued profits. As traditional regulation provides no incentives for a reduction in sales, DSM would result in utility expenditures to reduce demand. The result is that the utility cannot recover DSM costs or its lost sales, further reducing net revenue. In order to put these relatively equivalent options on equal footing, incentive regulation attempts to provide a means through which the utility is reward for DSM to compensate for some of the negative effects generated by its use.

Incentives can also be used to compensate for technological risk and the public goods aspect of information. There are currently several technologies, which if developed and commercialized, could provide electricity at lower costs and with much less damage to the environment than conventional technologies. These technologies include: renewable resources such a solar, photovoltaic, wind, and geothermal; clean coal technologies (CCTs); and second generation nuclear reactors. Both traditional regulation and the effects of competition have discouraged innovative technology adoption by creating an asymmetry of risks and rewards, and by the existence of information externalities (Zimmerman, 1988). There are significant risks associated with the commercialization of a technology, and the initial design and operation costs of a new plant. If regulators treat cost overruns in a strict fashion there is little possible reward for developing the technology. Moreover, once developed, competitors can learn from the first project and thereby receive a comparative technological advantage that can be used against the original developer/builder. This form of learning externality or "free rider" effect is present in both competitive and regulated industries. It is this free-rider problem that becomes a force in slowing and/or hampering technological growth.

Such an effect is unfortunate since it requires only 4-5 projects to perfect our knowledge of a technology and its costs (Flaim, Seretakis and South, 1989). The capital cost learning curve (Figure 1) depicts the possible gains from waiting in the case of free riders, or the gains to society from accelerating adoption of new technologies. To cope with the risk asymmetries and free rider problem, incentives can be designed to compensate or encourage utilities (and non-utility generators, NUGs) to adopt these technologies (McDermott et al., 1992). These incentives attempt to create a level field in terms of risks and costs of




Source: EPRI 1989 TAG®

**FIGURE 1 Capital Cost Learning Curve (Source: EPRI, 1989)**

innovative and traditional technologies. In addition, it is the innovative technology that may best aid the electric power industry (and every boiler-using sector of the economy) to comply with the requirements of the CAAA of 1990.

Lastly, incentive regulation can be (and has been) used to encourage efficiency in operation and construction. The incentive regulation provides an impetus for the utility to minimize costs in order to receive greater net revenues. Greater efficiency by the utility results in a cost savings for society as a whole. Incentives can also provide a means of limiting the risk associated with new project construction. By providing a reward to control costs efforts will be expanded to minimize cost overruns and promote a level of stability in capital cost forecasts. These effects are depicted in Figure 2.

### 2.2 Historical Use Of Incentive Mechanisms

The use of incentive regulation can be traced back to 1855 with use of the sliding scale rate-of-return approach by the Sheffield Gas Act of 1855 (Evetts, 1922). However, incentive regulation has never been adopt in any wholesale manner, but more in a piecemeal manner aiming at encouraging efficiency (Johnson, 1985). Regulators in the past have used the following incentives:

- regulatory lag
- automatic rate adjustment
- zone-of-reasonableness rate-of-return
- prudency/used and useful tests
- fuel adjustment clauses
- operating incentives
- construction incentives
- incentive rate of return/sliding scale plans.

#### 2.2.1 Programs and Description

Among the generic approaches, state regulators have attempted to formalize the concept of the zone-of-reasonableness for rate-of-return calculations as a means of stimulating

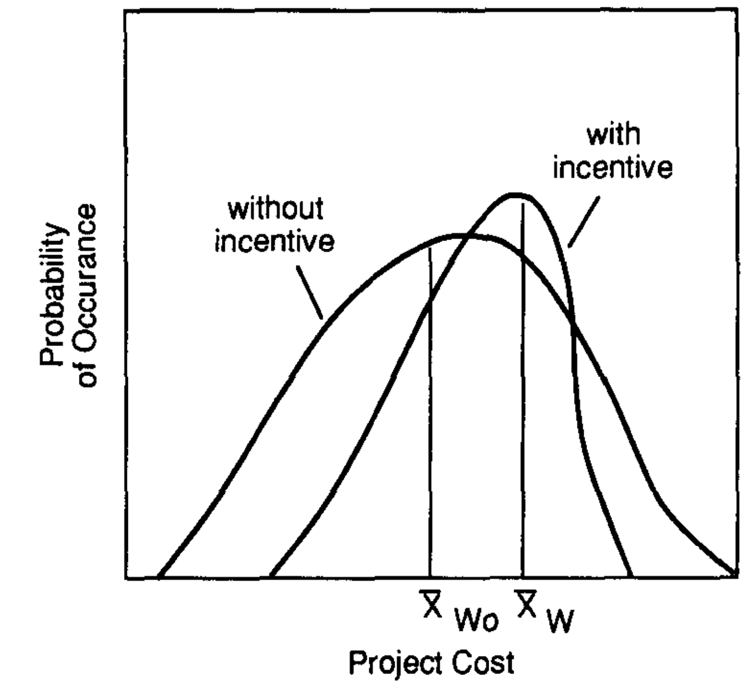



**FIGURE 2 The Effect of Incentives on Expected Project Costs and Variances**

efficiency.[5] Florida, Michigan, South Carolina, and Virginia have all employed rate-of-return adjustment mechanisms that are considered to produce returns that are still fair but provide for penalties and rewards (Nolan, 1981). Perhaps the most formal zone of reasonableness mechanism was that developed by New Mexico known as the COSI plan (Cost of Service Index) where a formal zone of reasonableness for equity returns was defined along with a

[5] Prior to the Hope Natural Gas Case, it was established that a "fair" rate of return would lie within a "zone of reasonableness" that would be determined as a question of fact by an administrative tribunal, see Federal Power Commission V. Natural Gas Pipeline Co., 315 US 575, 585-86 (1942) where it was noted that:

> *By long standing usage in the field of rate regulation the 'lowest reasonable rate' is one which is not confiscatory in the constitutional sense . . . assuming that there is a zone of reasonableness within which the commission is free to fix a rate varying in amount and higher than a confiscatory rate, . . . the commission is also free under Section 5 (a, 15 USCA Section 717d a) to decrease any rate which is not the 'lowest reasonable rate'. It follows that the Congressional standard prescribed by this statute coincides with that of the constitution, and that the courts are without authority under the statute to set aside as too low any reasonable rate adopted by the commission which is consistent with constitutional requirements.*

From this it would seem the rate-of-return must be set equal to the cost of capital in order to ensure a chance that the companies market value will equal book value and hence avoid the issue of confiscation. But, it is only the chance to earn this return and not a guarantee.

formal lag adjustment period which allowed the utility to reap the reward of returns above the maximum for a specific period and which punished the utility for returns less than the minimum. At the time of adjustment the rates are adjusted to bring the utility back within the zone; see Kaufman and Profazich (1979).

The so-called "sliding scale" approach was employed in England during 1855 where the Sheffield Gas Act of 1855 permitted the company to pay a dividend of 8% if gas prices were over 84 cents (Evetts, 1922). It could, however, declare dividends of 10% if the price was less than this level. In the United States the Washington Plan was employed from 1925 to 1955 to regulate Potomac Electric Power Co (Holthausen, 1979). If the companies earnings rose above 7.5% the rates would be lowered in the following year to absorb half the excess. If earnings fell below 7.5% for five years, 7% for 3 years or 6.5% for one year, rates would be increased to allow a 7.5% return.

The FERC has contemplated a sliding scale type mechanism in the Alaskan gas pipeline case. There the incentive rate of return (IROR) mechanism explicitly accounted for the risks created by the introduction of the mechanism itself with the result that a "risk premium" would be included to compensate in part for this additional risk in order to maintain capital attraction and compensate for the business risk associated with the project.[6]

Besides the incentive mechanism focusing upon the rate-of-return, states began in the late 1970's to employ lag mechanisms in the treatment of automatic fuel adjustment clauses. These lags were designed to induce efficient fuel choice and to minimize the fuel cost and purchased power expenditures of the utilities (FTC, 1977; ICC, 1979). The problem facing regulators in the 1970's involved rapidly rising fuel costs due in part to the OPEC oil embargo. Regulatory lag as an incentive, in effect, transferred more of the risks to utilities than warranted by conditions. Likewise, an automatic fuel adjustment clause resulted in the

[6] Order No. 31, *Determination of Incentive Rate of Return, Tariff and Related Issues,* June 1979.

consumer bearing the full cost of fuel purchasing decisions, insulating utility management from the cost of errors. Automatic adjustments also did not provide any incentive to utility management to investigate ways to minimize costs.

Two approaches were employed in order to assure a sharing of these specific and unique risks arising in the fuel supply market. One approach was a time-employed lag in the adjustment process that forced the utility to cover the difference between the present revenue allowed for fuel costs and actual fuel costs (Violette and Yokell, 1982). This ostensibly created an incentive for utility managers to employ management techniques that would minimize the difference in costs and thereby reduce the future price increases faced by consumers. The second technique was the establishment of a target fuel price based on appropriately weighted market prices for boiler fuels. This was then combined with an adjustment process that would allow a partial pass-through or price reduction that was based on the difference between the actual and target fuel costs. For example, if actual fuel costs were higher than target fuel costs by one cent per kWh, the adjustment mechanism would allow a one-half cent increase in fuel costs. Likewise, if actual fuel costs were below the target a one-half cent decrease would be passed-through to the customer.

This is an example of how specific incentive mechanisms can be employed to address unique risks associated with specific aspects of a utility's decision-making process. Such mechanisms can have a profound effect on both short-and long-run decisions. The fuel adjustment incentives influence the dispatching of power, the maintenance scheduling of plants, and fuel purchasing strategies in the short-run. In the long-run such mechanisms influence the plants selected for future construction, long-term purchasing strategies on the bulk power market, and the speed of new plant construction. In designing such incentive mechanisms, care must be taken to evaluate both the short-and long-run implications to ensure that a strategy is adopted that minimizes long-run utility service.

Many states are beginning to analyze and adopt objective efficiency standards that are used as a basis for adjusting a utility's allowed rate-of-return upward or downward.[7] In some cases management audits are used as the basis of evaluation,[8] while in other cases measures of overall productivity are employed to evaluate a utility's success in controlling costs and managing operations correctly (Crew and Kleindorfer, 1987; Seagraves, 1984; Baumol, 1982; Gale, 1982; Costello, 1984). More recently, measures of total factor productivity have been examined by both state commissions and utilities. For example, Otter Tail Power Company has been employing a total factor productivity program internally since the early 1980s.[9] The employment of such mechanisms and measures is indicative of the industry's recognition of the need to provide rewards to offset risks, and rewards (punishment) to management for making good (bad) decisions.

Risk asymmetries and the level of risk has also been regulated. Whereas in the past risk analysis was relegated to the analysis of the allowed rate-of-return, in today's environment risk analysis is employed in construction, fuel choice, conservation, and other important policy decisions of both companies and PUCs.

Risk sharing mechanisms are employed to lower the ultimate costs of transactions.[10] Risk sharing issues arise before regulatory commissions on a broad range of questions from rate design, fuel cost recovery, excess capacity and construction planning. One of the most frequently employed forms of risk sharing used in regulation today is the phase-in of rate base additions. By adopting a phase-in approach regulators achieve a number of objectives, including the sharing of new plant costs between utility stockholders and consumers. If it

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[7] See Standards for Public Utility Management Efficiency, 1985, 65 PUR 4th 189, Iowa S.C.C.

[8] See Management Audits, Electric Utilities, 1986, 73 PUR 4th 66, 68, West Virginia P.S.C.

[9] See Kjellerup (1984, 1985, 1988) for an in-depth discussion of the Otter Tail program and references therein.

[10] See Stutz (1986) and for a counter perspective see Markham (1988) — this article lists 21 examples of risk-sharing cases heard before regulatory commissions.

is known in a prospective fashion that costly plants will be phased-in rather than placed in rate base all at once, the utility will have an incentive to minimize construction costs. Phase-ins are also used to (1) reduce rate shock, (2) maintain rate stability, (3) match benefits and costs of a plant to customers over time, and (4) preserve the financial integrity of a utility.

Another approach to risk sharing is the use of prudence reviews, where the reasonableness of construction expenses are evaluated and any part disallowed is considered to represent the stockholders share of expenses. The problem with prudence reviews lies in the ambiguity surrounding the definition of prudence.[11]

The risk that a full recovery of costs may not occur can lead some utilities not to undertake investments that are of a legitimate nature. As much as 35.9% of a plant's construction costs have been disallowed from rate base in the case of Nine Mile Point Unit 2 in New York, with an average of 15.9% disallowed for the twelve plants considered as of 1987 (Laros and Houbould, 1987).

### 2.2.2 Initiatives Promoting Development of New Incentive Mechanisms

Historically, incentive regulation has concentrated on construction and production efficiency; the appropriate mechanisms were used to further these goals. Today, incentive regulation is needed for a wider range of problems involving resource choice and technology adoption. The growth of integrated resource planning (IRP), passage of the Clean Air Act Amendments of 1990 (P.L. 101-549), and increased federal interest in a national energy policy has led to a recognition that new incentives are needed to address these initiatives' goals.

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[11] The first attempt at such a definition was given by U.S. Supreme Court Justice Brandeis:

> *The term prudent investment is not to be used in a critical sense. There should not be excluded from the finding of the vase, investments which, under ordinary circumstances, would be deemed reasonable. The term is applied for the purpose of excluding what might be found to be dishonest or obviously wasteful or imprudent expenditures. Every investment may be assumed to have been made in the exercise of reasonable judgement unless the contrary is shown.*

Separate, Concerning opinion of Justice Brandeis, Missouri ex rel. Southwestern Bell Telephone Co. V. Missouri Public Service Commission, 262, US 276, PUR 1923C 193, 1923.

Like least cost planning, IRP attempts to choose the mix of electricity conservation and capacity supply resources that generates the maximum amount of net benefits to the citizens of the state in question.[12] These benefits not only include efficient electricity production, equity, and reliability, but also concerns over local/state/regional (even global) pollution, the use of state produced resources (i.e., coal, oil, natural gas), and overall effects of IRP on the state economy. As mentioned previously, there is a disparity of value between utilities choosing capacity versus DSM. Incentive regulation to balance these options has already been enacted in several states such as New York, Colorado, Wisconsin, Michigan, California, and Washington to name a few (NERA, 1991).

Title IV of the CAAA provides utilities with an incentive to reduce $SO_2$ emissions in the most cost-effective manner as possible. Regulatory treatment of $SO_2$ allowances will create important incentives for differing compliance options. The treatment of allowances and compliance options will have important implications for the future development of this market and will effect the costs of compliance. Compliance costs in turn will impact rates and the state economy.[13]

At present three important incentive regulations can be considered under the CAAA of 1990: first is the treatment of allowances within a utility's cost structure; second is the issue of preapproval and prudency reviews; and third is incentives for technological adoption.

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[12] IRP has also been examined on a regional scale to deal with problems such as cross-border pollution and multistate utility holding companies. The IRP issue on a regional scale may be a more divisive project because of individual state's attempts to maximize their own welfare with less concern for other states in the region. Regional planning has occurred in the northeast states covered by NEPOOL (Vine, Crawley and Centolella, 1991).

[13] An extremely important issue is the potential conflict between the goals of the CAAA of 1990 and state IRP. From the Act's perspective, cost-effective compliance and achievement of $SO_2$ reduction is the chief goal. For the state, utility compliance actions such as scrubbing or fuel switching may come in conflict with the state's least cost plan. An example where the goal of the Act and IRP come into conflict is the issue of fuel switching to low sulfur coal in high sulfur coal producing states. While it may be optimal from the utility perspective to fuel switch, the cost of this fuel switching may impact the state's economy greatly. The state may find that restricting compliance choices will lead to a more optimal solution. This issue remains to be resolved and will have important implications for the success of both the Act and IRP.

Optimally, allowances should be included in a utility's total cost in such a manner as to prevent distortions in the choice of compliance option.[14] Preapproval and prudency reviews provide an important incentive for purposes of risk sharing and reducing compliance costs. Through the use of preapproval, the utility can be assured that a chosen option (which is favored by the state) will be allowed into rates, thereby mitigating any inefficient hedging behavior on the utility's part.[15] The third incentive encourages certain technological options that may be optimal from a state and even a utility perspective, but may not be optimal in terms of aggregate compliance costs for the Title IV program. These incentives include: preapproval of technology choice (scrubbers), tax credits for using local coal, and accelerated deprecation on certain technologies (CCT, scrubbers).[16]

The National Energy Strategy (NES) as envisioned by Congress and the Administration will attempt to:

> *reduce the Nation's dependance on imported oil, to provide for the energy security of the Nation and for other purposes...* (S.1220)

The NES attempts to achieve a wide range of goals including, (1) the development of new, cleaner, innovative electricity generating technologies, (2) improving competition in the natural gas and electricity supply markets through the "Mega-NOPR" and revisions to PUHCA and PURPA, (3) improved transmission access, (4) improved corporate average fuel economy (CAFE), (5) open additional lands for exploration of oil and gas reserves, and (6) reduced emissions of criteria and greenhouse gas pollutants through these measures.

[14] For further details on the various methods of allocating the value of $SO_2$ allowances, see Rose and Burns (1991). In addition, some states may find it optimal to distort compliance option choice.

[15] This behavior could include a wide variety of compliance options that the utility may expend manpower and capital to examine instead of choosing the option that best fits the utility's needs.

[16] In addition, legislative mandates have been passed requiring scrubber use and local coal use. See Section 5.

Of particular interest to incentive regulation is the desire to promote innovative electricity generating technology.[17] Within Senate Bill 1220, Title XIV, Section 14204, the FERC is authorized to allow incentive regulation including incentive rates-of-return (IROR) and accelerated depreciation along with other incentives of its choosing in determining wholesale rates for the development of CCTs. The FERC is also prompted to encourage states to adopt incentives for CCTs. The incentive program would run for 5 years which could be extended. Cost caps and preapproval prudency for CCT projects that fall within these caps would be allowed along with prohibiting states from including CCT demonstration projects within a utility's avoided cost.

In addition to the incentives indicated in S.1220, the CCT program solicitations have allowed joint federal, state, and private funding for the development of CCTs. The use of regulatory incentives in this case is to overcome risk asymmetries, technological risks, and the "free rider" problems associated with any innovative technology.

Several states have already implemented CCT incentive regulations within their responses to the CAAA of 1990. The high sulfur coal state's incentives are listed in Table 1. These regulatory incentives can be seen as addressing the problems of IRP, least cost compliance with the Act, and furthering the NES. Section 4 will more fully describe the issue of incentive regulation for technological development and issues surrounding CCTs.

## 3 PROPERTIES OF INCENTIVE MECHANISMS

Incentive regulation is able to address a wide variety of efficiency issues through a varied array of mechanisms. However to be effective, the incentive mechanism must have certain desirable properties (see McDermott, 1980). Without these properties the incentive at least will be nothing more than wasted work hours spent drafting the regulation, and at

[17] Revisions to the structure of the industry (PUHCA), competitive procurement, and transmission are all extremely important regulatory issues. In particular, incentive regulations applied to the procurement of power and the opening of transmission grids may be particularly interesting as an incentive application. These issues, however, will not be addressed in this paper.

**Table 1 High Sulfur Coal States and Compliance Responses to Title IV**

| State | Incentive Programs |
|---|---|
| Illinois | Preapproval of scrubber technology<br>CWIP allowed for scrubber installation<br>Mandating scrubber and state coal use at certain facilities |
| Indiana | Utilities may seek preapproval for acid rain compliance plans<br>CWIP is allowed |
| Ohio | CWIP for utilities participating in scrubber program<br>Tax incentive for state coal use |
| Pennsylvania | CWIP for scrubber and innovative technology<br>Utilities may seek preapproval of acid rain compliance plans<br>Tax incentive for state coal use |
| West Virginia | CWIP for scrubbers and innovative technology construction<br>IROR for CCT projects<br>Accelerated depreciation for scrubbers and CCT type projects |

Source: Illinois Senate Enrolled Act 621; West Virginia Code Chapter 24,-2-1g, Article 2g; Clean Coal/Synfuels Letter, *Pennsylvania Coal Plan Provides Support for Newer Technologies*, May 6, 1991, p. 1,3; Indiana Senate Enrolled Act 514; and Ohio Senate Bill 143.

worst distort the market causing undesirable effects on reliability and rates. The regulatory incentive mechanism should be (McDermott and South, 1991):

1. symmetric
2. non-distortionary
3. administratively feasible
4. rewards and penalties tied to managerially controllable outcomes
5. forward looking, not historic
6. easy to monitor and evaluate performance.

One factor that must be recognized with incentive regulation is that all penalties and all rewards can distort the behavior of the affected party.[18] The regulatory incentive should reward the utility for good performance while imposing penalties for bad performance. Traditional regulation has tended to distort the performance/reward risks of the utility industry. Cost savings on the part of the utility have resulted in the savings being passed on to ratepayers. Poor performance, however, has always been penalized by the regulators, stifling potentially cost-saving attempts by utilities. If a firm manages to generate cost savings because of greater efficiency or taking a risk, the shareholders should be entitled to keep a significant share of the benefits. Conversely, bad performance should be penalized and not treated in a business-as-usual fashion. The symmetry of rewards and penalties will push firms towards operating in a more efficient manner.

An important issue that the regulatory community has not addressed is the tendency to apply incentive regulations in a piecemeal fashion (Johnson, 1985). The tendency has been to concentrate the incentive on individual cost components such as fuel costs, capital costs, the rate of return, construction costs, etc. While these incentive programs are valuable for assuring efficiency in these areas, there may be a case for too much effort being applied to

[18] The magnitude of the distortion in many cases is uncertain. One of the chief problems of policymakers is determining by "how much" a policy will alter behavior. With little knowledge about the magnitude of effects, the policymaker may find costly projects having too little effect or having effects much larger than desired (i.e., Federal Reserve Board open market operations).

a particular utility component (such as fuel purchases) while ignoring other areas where no incentive is offered, but savings could be made. Incentive regulation which is tied to a narrow target or activity may result in distortion of management effort allocation.[19]

Administrative feasibility of the incentive is also extremely important for its success. Factors such as ease of estimation, understandable outcomes, flexibility, ease of implementation, ease of monitoring, "dovetailing" with current regulation, and legality are all factors that must be considered before and during the period that the incentive is implemented.

Ease of estimation embraces determining the magnitude of the incentive required for program success, and relative easy by which the incentive-to-impact magnitude can be determined. Incentive mechanisms that are extremely difficult to calculate may result in too many resources being devoted to a project with relatively little gain. Understandable results are necessary to determine program success (i.e., was this effect caused by the incentive or something else?), and if the incentive should be altered in type or magnitude. A incentive program with demonstratable success may indicate that this mechanism can be applied to other problems successfully.

Flexibility of the incentive is required in order for successful implementation. An incentive program that is not able to be applied in most typical utility situations (general construction, operations, fuel purchases) may be useless. Excessive reporting requirements and restrictions on when the incentive can be used also reduces flexibility. The ease of incentive program implementation will effect both regulator and utility costs. Low start-up costs will reduce the resource burden on the regulator and allow the utility to take advantage

[19] An analogy can be drawn with respect to the Averach-Johnson argument that rate-of-return regulation encourages over-capitalization. Traditional regulation allows a return only on capital expenditures, all other expenditures are simply passed through with no gain to the utility. Therefore, the utility has an incentive to purchase more capital because of its greater rewards. This is similar to the misallocation of managerial effort on "parts" of the utility where additional returns may be generated. Time allocated to these sectors results in too much effort being allocated while other efforts may suffer. A point can be made for incentives tied to a narrow target if the target is so important that distortions of effort would result in tremendous efficiency (or similar goal) gains.

of the incentive as soon as possible with lower adjustment costs. Program delays, slow starts, and expensive start-up costs may prove too labor intensive for regulatory agencies and will encourage utilities to continue operations as before because of the greater costs to adopt the incentive.

The ability to monitor progress and evaluate performance is essential. Monitoring combined with penalties and rewards constitute the major input by regulators into the process. Without penalties for noncompliance or the ability to engage in false reporting of results, the regulated agent has an incentive to avoid compliance. The result in the case of incentive regulation for public utilities would be little progress towards more efficient operations and greater costs to ratepayers. With monitoring present, incentives to evade compliance or "cheat" are reduced. An incentive program that is difficult to successfully monitor (high probability of nondetection of violation) and costly should not be implemented, but rather a simpler program with possibly more modest goals and greater chances of success should developed.

The ability of the program to dovetail or fit into the present regulatory regime is also necessary for program success. The regulatory incentives should complement each other to aid in the reaching the goal of greater efficiency. Contradictory regulations and incentives will produce greater costs for ratepayers, shareholders and regulators, and result in uncertain program results. Finally, the program must be legally viable. Illegality resulting from improper restrictions on property use, methods of accounting, conflict with federal law, or unjust favoritism will result in wasted effort on both the regulator and utility's part. An incentive that results in extensive (and expensive) litigation because of its faults results in a loss to all the parties concerned.

The regulatory incentive should also be linked to factors that the utility management has control over. For events such as fuel shocks, recessions, high inflation, or acts of God, the management of the utility has very little ability to diversify away from the risks of these occurrences (with the possible exception of some fuel risks). The incentive should attempt to isolate these effects and render them neutral for purposes of assigning rewards and penalties.[20] Management still should maintain prudent levels of reliability and precautions against force majeure events to minimize costs, but the incentive should not penalize if prudent preventions were taken.

Lastly, incentives must be forward looking in order to preserve fairness and encourage efficient behavior. Retrospective incentives which punish firms for actions not taken in the past is clearly unreasonable.[21]

Finally, the results and performance of the incentive program should be evaluated. Questions regarding the achievement of improved performance, minimization of risk, and elimination of distortions in investment, activities and effort should all be examined. Those regulatory incentives which showed success in one or any of these categories may be able to be applied successfully to other problems. If the incentive failed to act as desired then the issue of what can be done to improve the instrument, or the need to discard the incentive, can be discussed.

Incentive regulation can (and has shown itself to) be a powerful tool to achieve more efficient utility operations. For the incentive to be effective, the regulator must address a variety of potentially difficult questions about its function and effect on the regulated party. To determine if the incentive was able to achieve desired outcomes, the incentive program must be evaluated.

Section 4, will present the regulatory problem of innovative technological adoption and regulatory incentives needed to achieve the implementation of the technology. Incentive

[20] This, however, is easier said than done. For example, construction of a capital-intensive plant will be affected by events such as inflationary trends, changes in the cost of capital, labor problems, and technological difficulty. A cost cap incentive could be adjusted for inflationary pressures or unforseen spikes in interest rates, or labor unrest by raising the cost cap to match the price increases.

[21] This is true as it may pertain to projected construction, fuel supply contracts, and similar activities. Retrospective regulation when one considers issues of hazardous waste disposal penalties for improper disposal may be entirely reasonable such as EPA's Superfund program.

regulations for the adoption of CCTs serves as a means of commercializing a valuable technology and achieving some of the goals set forth in the Title IV of the CAAA of 1990, namely the reduction of $SO_2$ in a cost-effective manner.

## 4 CLEAN COAL TECHNOLOGY INCENTIVES AND THE CLEAN AIR ACT AMENDMENT OF 1990

The central problem with the development and commercialization of innovative, electricity generating technologies has been the exposure to excessive technological risk and the associated regulatory risks. Given the uncertainty regarding construction and operating costs, and the risks of under-performance or failure to operate in terms of heat rates, downtime, and pollution control, the innovative technology faces significant hurdles in the traditionally conservative utility industry. Under traditional regulation, reliability and an asymmetry of risks and rewards tends to force capacity choice away from riskier technological options. In addition, regulators will be concerned that insufficient incentives exist for the utility to control the construction costs of a new plant. In effect, a dual incentive mechanism must be created — it must offset the technological risks and provide an incentive to cost-effectively complete the project.

In part, the Clean Coal Technology Program (CCTP) solicitations has helped advance the development and deployment of CCTs in industrial boiler, independent power producer and utility applications. With the CCT solicitations some of the development and implementation risks have been reduced by federal and state funding grants. However, the widespread commercialization of CCTs may still be years away.[22] In order to compensate for the extraordinary risks associated with CCTs, and the presence of free rider behavior,

[22] The incentives and barriers to CCTs should be considered the same as most types of innovative technologies. The central difference separating these coal technologies from other innovative technologies is the fuel. The general perception of coal is as a fuel that results in high emissions of $SO_2$, $NO_x$, particulates, and $CO_2$. The CCT project may find siting difficult due to these perceptions, although siting may be easier in the face of perceptions rather than technical needs associated with wind, solar, and geothermal energy; the perception problem also affects second generation nuclear reactors.

regulatory incentives are needed to promote the commercialization of CCTs. The eventual commercialization of CCTs is desired due to perceived low operation costs, CCTs use a plentiful, low cost fuel, and CCTs generate significantly less $SO_2$, $NO_x$, particulate, and $CO_2$ emissions relative to conventional coal-burning technologies. The availability of CCT as a compliance option for Title IV of the CAAA of 1990 would greatly aid utility compliance and could generate additional benefits for the utility.

The regulatory incentives for CCT commercialization can be divided into two categories: regulatory incentives to reduce the risks of adopting CCT (innovative technology) and incentives that reward risk taking. The ICTAP (1989) report indicates four central risks associated with adopting an innovative technology, and in particular CCTs: capital risk, operating risk, regulatory risk and environmental risk.

These risks can be described briefly as follows: Capital risks are associated with the possible loss of either or both the return <u>on</u> capital and/or the return <u>of</u> capital. This can occur when a PUC disallows all or portions of the utility's construction costs, or reduces the allowed rate of return on its investments. Operating risks are associated with the potential failure of the plant to perform up to its expected efficiency or fails to operate entirely. Regulatory risk is a generic term encompassing the PUCs treatment of operating and capital expenses within the regulatory process; for example, prudency or used and useful disallowances. Environmental risk entails the possibility that the technology adopted or construction site will not meet local environmental standards. Each of these risks or a combination of them are faced by a utility adopting a new power plant technology.

Incentive regulation can serve a mitigating role for the risks faced by innovative technology development. The following incentives are proposed to aid in the reduction of risks and presenting rewards for risk taking. The incentives are:

1. Prospective prudency
2. Prudent abandonment rules

3. Accelerated depreciation
4. Rate-base treatment of deferred taxes
5. Construction work in progress
6. Avoided cost rate adjustments
7. Expensing demonstration costs
8. Incentive rates of return
9. Amortization of abandon/canceled plants
10. Pre-approved capital expense caps

In Table 2, each of the alternative incentives are classified with respect to the risk addressed and whether they are risk reducing or reward incentives. In some cases the incentive is capable of mitigating more than one type of risk and could serve as either a risk reducing or reward incentive. As mentioned in Table 1, the states producing high sulfur coal havc implemented some of these incentives, with West Virginia the farthest ahead in implementing regulatory incentives.

Prudency rules, whether they cover new capital costs, or the abandonment or cancellation of a plant, are essentially designed to reduce the capital cost and regulatory risks. If utility management understands the rules under which they are making investment decisions, the elimination of these uncertainties will result in a more cost-effective set of decisions. Preapproved capital expense caps act in a similar fashion with the additional advantage that a financial reward can also be earned if construction costs can be kept below the cap level. This could be achieved by allowing the utility to place in rate base the expense cap when actual construction costs are less than that level.

The amortization and depreciation programs provide an accelerated return of capital to the stockholders which, in a present discounted value sense, increases the reward to stockholders and shortens the payback period of the investments. Construction work in

**TABLE 2 Risk Classification**

| | Capital Risk | Performance/ Operating Risk | Regulatory Risk | Environmental Risk |
|---|---|---|---|---|
| Reduce Project Risk | Prospective Prudency Preapprove Capital Expense Caps.<br><br>Construction Work in Progress (CWIP) | Rapid Amortization of CCT Expenditures | Eliminate Retroactive Used and Useful Tests | Pre-approval Accelerated Siting Process |
| Reward Risk Taking | Incentive Rate of Return | Immediate Cost Recovery through FAC's of CCT Expenditures<br><br>Additional Cost Recovery via Avoided Cost Pricing for CCT | Prudent Abandonment Rules<br><br>Amortization of Abandoned/ Canceled Plants | Discretionary Use of Bonus Emission Allowances |

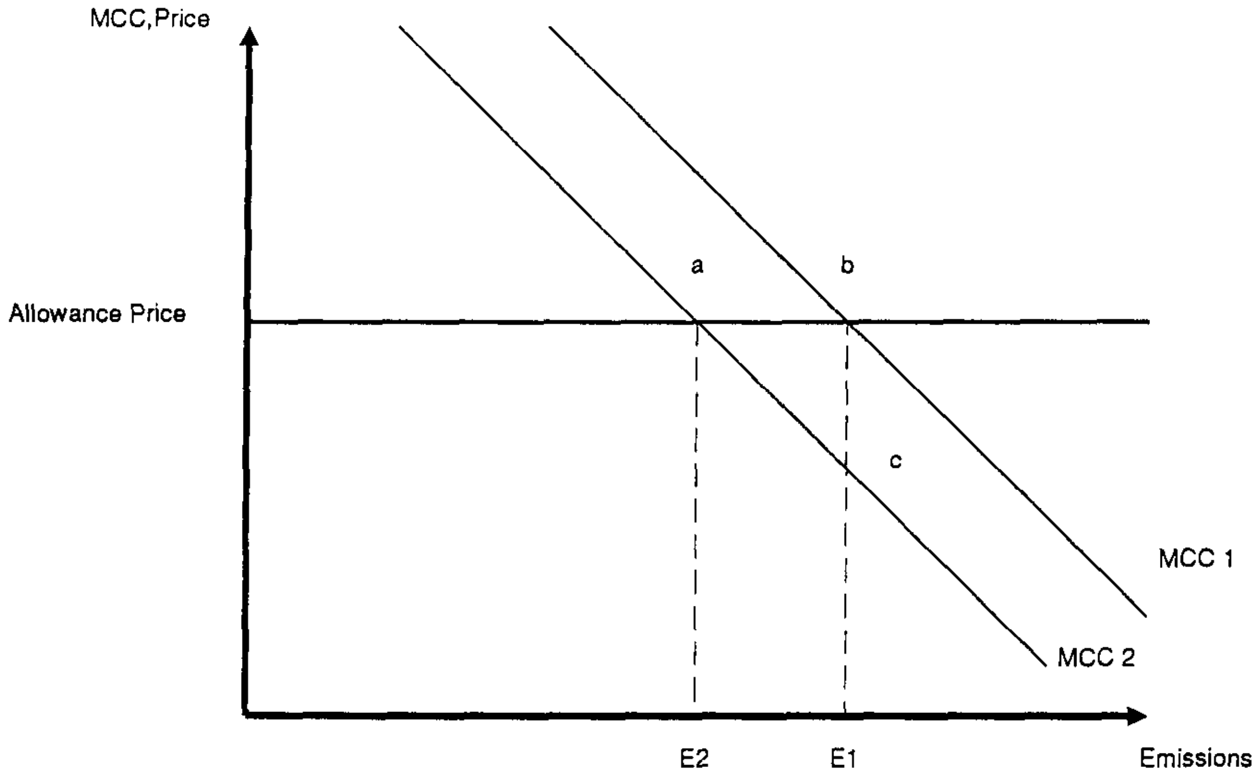
progress (CWIP) works in a similar fashion but has the added advantage that the cash flow occurs during the construction period, while the amortization/depreciation programs provide cash flow after the projects completion. By providing cash flow during construction additional savings can occur from reduced borrowing needs.

Under the accelerated depreciation program intertemporal cash flows are altered by the change in the timing of the companies tax bill. If the deferred taxes that accumulate are treated as a rate-base item the stockholders will earn an additional return on the project. By expending some or all of the project's costs, a utility reduces the investment payback period and acquires an accelerated cash flow. Once again, if these costs are passed through to customers during the project it acts like CWIP in reducing the overall financing costs of the project.

With regard to IROR, regulators have a number of options available. They could estimate what the premium for undertaking similar risks is within the capital market and allow the utility to earn this rate on that portion of the companies rate base associated with the CCT plant. Alternatively, they could simply prescribe a return that is sufficient to induce utilities to adopt CCT projects.

In many cases a combination of these policies is available that simultaneously offset risks and provide rewards for controlling project costs. In some cases, regulators may allow utilities to reveal their own preferences by selecting the incentives of their choice to either offset risks or be rewarded for bearing risks in conjunction with cost control incentives. Since not all firms or managers have the same preferences towards risk bearing, allowing a choice of incentives will reach a larger portion of the utility marketplace.

How does the use of regulatory incentives aid in achieving the goals of Title IV/CAAA of 1990? In Section 1, we briefly characterized Title IV as having two goals: the first goal is the reduction of acidic precursors which cause acid rain, the second is the compliance flexibility granted utilities by the use of transferable $SO_2$ allowances. The flexibility generated by the allowance program results in an overall savings with respect to compliance costs. One of the important properties of allowances envisioned by economists is the additional incentive created for technological innovation of pollution control technology. If the innovator is able to control emissions at a much lower cost he would control emissions until the marginal cost of control is equal to the market price of the allowance. So, the firm reduces emissions and has allowances available for sale. The firm has created value by reducing emissions (see Figure 3).




Allowances held = level of emissions (E2 or E1)

Net Benefits form Innovation = abc

**FIGURE 3 Excess Allowances Create Value**

The incentive for cost minimization and innovation through the use of the market may, however, be stifled if (1) regulatory barriers to trading, (2) utility hedging of allowances, or (3) distortion-causing regulatory incentives (i.e., scrubber incentives, mandating technologies and fuel use) are employed. A danger exists that incentives, which explicitly distort economic choices facing a utility, will limit the ability of the market to develop, and consequently, the utility will rely less on the market to achieve compliance. The result may be greater costs for shareholders, ratepayers, and society. Regulatory incentives, if properly applied, can help to achieve cost-minimizing compliance with Title IV and help promote innovation of more environmentally-benign technologies. The way to achieve lower compliance costs with Title IV is to directly reward the innovation of such technologies.

Regulatory incentives for the reduction of risk and the encouragement of risk taking for promoting innovative technologies is desirable. The regulatory incentive will be nondistorionary since it reduces uneconomic risks, such as technological and regulatory risks, and creates a level playing field. Incentive regulation can be used to overcome the free rider problem as innovative firms are able to reap greater rewards. And repowered or greenfield CCTs (or other innovative technologies) result in allowances being freed for other uses creating value.[23]

## 5 SUMMARY AND CONCLUSIONS

The use of tradeable $SO_2$ allowances fundamentally alters the means by which pollution will be regulated. Additional market/incentive-based instruments for environmental protection have been proposed for the control of greenhouse gasses, stratospheric ozone depleters, tropospheric ozone control, water-borne pollutants, and solid waste disposal. The harnessing of private information and the market should encourage cost-effective compliance with the mandated standards. In addition, incentive mechanisms stimulate greater innovation as emission reduction can generate greater cost savings than command and control approaches.

In terms of Title IV of the CAAA of 1990, incentive regulation can also play almost as important of a role as emission allowances. Two scenarios can be envisioned. In the first, the market fails to develop in a timely manner resulting in greater compliance costs and less technological innovation. Incentive regulation can serve several mitigating roles. Regulation

[23] It is possible that the use of innovative technologies via repowering or new construction (greenfield) will not be the least cost solution to compliance. In these cases, incentive regulation from a societal point of view is still optimal as it reduces risk asymmetries and reduces the free rider problem. However, the use of CCTs (or other innovative technology) may not be the optimal compliance method for a utility system when compared to fuel switching or scrubbing.

can be promulgated insuring nondistorionary treatment of allowances. This will in-turn encourage cost-effective choices of control equipment, which should transfer this cost information into allowance market price signals, hopefully reducing market uncertainty. Prospective prudency review may also encourage quicker and lower cost market formation. Early approval of compliance choices will aid the utility cost minimization without having to devote efforts to hedging behavior to protect against unfavorable prudence reviews. Incentive regulation can serve the role of promoting innovative technology via "level playing field" for all compliance options where the individual costs and merits of each technology can be judged. Technologies such as CCTs can greatly aid in utility compliance, controlling $SO_2$ emissions to a point where excess allowance are freed for other uses.[24]

The second scenario is the allowance market for $SO_2$ does development in a timely manner and results in compliance cost savings (as compared to command and control) for the electric utility industry. What role can incentive regulation play? Incentive regulation can be used to further promote efficient utility operations in terms of power procurement, operations, fuel procurement and the like. Incentive regulation can also aid the development of innovative technologies. The combined incentives from regulation and the $SO_2$ market may result in a faster adoption of technologies such as CCTs.

The issue of IRP and Clean Air Act compliance has already been alluded to. The conflict between state goals of achieving the maximum welfare from it energy use and the cost minimizing goal of Title IV may conflict. The PUCs will encourage the use of compliance options which, for example, maintain their high sulfur coal markets by the use of scrubbers. While this policy may be judged the best form the state's view, from a utility and social standpoint, if scrubbing is not the least cost option, the policy is nonoptimal. Technology

[24] A variant of Scenario 1 is that the PUC creates distortionary incentive regulations that results in greater compliance costs for the state's utilities. In this case, the motivation to use incentive regulation to aid the development of a allowance market with efficient prices and optimal compliance option choices is limited. Incentive regulation may, however, be used by states to encourage the development of technologies that fosters state IRP and is optimal from a compliance cost standpoint.

forcing and trading restrictions by PUCs may limit the effectiveness of the $SO_2$ allowance market.

Incentive regulation may be used to achieve IRP goals and Clean Air Act goals even when they are in conflict. For high sulfur coal states, incentive regulation for the promotion of CCTs may serve the purposes of continuing maintenance of high sulfur coal markets and offering a least cost compliance option for the state's utilities. The allowances freed by developing CCTs may then be used to offset the cost of the incentive for shareholders and ratepayers.

Incentive regulation provides a powerful tool that can be used to achieve greater efficiency in the public utility industry. Through balancing resource choices, promoting cost efficiency, and reducing asymmetric risks, incentive regulation has the potential to reduce the societal cost of producing energy. Incentive regulation is also an important tool for compliance with Title IV of the 1990 CAAA. The nondistorionary use of incentives can aid the formation of a well functioning allowance market and promote innovative technology. In the event of market failure, incentive regulation can in many ways "jump start" the market buy encouraging trading and cost-effective compliance, and aid in the development of low cost control options. Thus, incentive regulation has important role to play in Clean Air Act compliance and all the potential conflicts that may arise between it and state interests.

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**DOE/CCT**
**CLEVELAND, OHIO**
**SEPTEMBER 23, 1992**

# IMPLICATIONS OF THE CLEAN AIR ACT AMENDMENTS OF 1990 ON COAL-BASED ELECTRIC CAPACITY PLANNING

I AM PLEASED TO HAVE THE OPPORTUNITY TO SHARE SOME OF OUR EXPERIENCES IN INDIANA REGARDING THE IMPACT OF THE 1990 AMENDMENTS TO THE CLEAN AIR ACT ON CAPACITY PLANNING BY OUR STATE'S MAJOR ELECTRIC UTILITIES, EACH OF WHICH HAS A PREDOMINANTLY COAL-BASED GENERATING SYSTEM.

AS A *FOUNDATION FOR MY REMARKS, PLEASE UNDERSTAND SOME BASIC* FACTS ABOUT ELECTRIC GENERATION IN OUR STATE:

1. NEARLY 95 PERCENT OF ELECTRIC GENERATION IN INDIANA IS COAL-BASED, WITH THE VAST MAJORITY OF THE COAL USED BEING HIGH SULFUR ILLINOIS BASIN COAL. OUR STATE IS BLESSED WITH SUBSTANTIAL RESERVES OF SAID COAL LOCATED LARGELY IN THE SOUTHWESTERN CORNER OF INDIANA. ADDITIONALLY, THE ECONOMY OF THE STATE AS A WHOLE AND THAT GEOGRAPHIC REGION IN PARTICULAR IS SIGNIFICANTLY INFLUENCED BY THE HEALTH OR LACK OF SAME OF THE COAL INDUSTRY.

2. THE INDIANA GENERAL ASSEMBLY, OF WHICH I WAS ONCE A MEMBER, HAS ENACTED SEVERAL RELEVANT STATUTES IN THE PAST DECADE.

(A) A CERTIFICATE OF NEED STATUTE PASSED ORIGINALLY IN 1983 WHICH IS ESSENTIALLY A PRE-APPROVED GUARANTEE OF BOTH THE NECESSITY OF GENERATING CAPACITY AND THE RECOVERY OF THE COSTS OF CONSTRUCTING SAME. THIS STATUTE ALSO NOW INCLUDES LANGUAGE WHICH REQUIRES THE COMMISSION TO DEVELOP A STATEWIDE PLAN FOR CAPACITY INCREASES AND ESTABLISH A UTILITY FORECASTING GROUP AT PURDUE UNIVERSITY TO PROVIDE TECHNICAL EXPERTISE TO THE COMMISSION IN THIS AND OTHER TASKS. THE MEMBERS OF THAT GROUP NOW ROUTINELY TESTIFY AS THE COMMISSION'S OWN WITNESSES AT CERTIFICATE OF NEED PROCEEDINGS;

(B) A LAW ALLOWING CONSTRUCTION-WORK-IN-PROGRESS (CWIP) RATEMAKING TREATMENT FOR PROJECTS NECESSARY FOR ENVIRONMENTAL COMPLIANCE. AS A GENERAL RULE, INDIANA DOES NOT ALLOW CONSTRUCTION-WORK-IN-PROGRESS RATE-BASING. RATHER, OUR LAW REQUIRES UTILITY PLANT TO BE "USED AND USEFUL" BEFORE ITS INCLUSION IN RATE BASE. HOWEVER, THIS CWIP PROVISION WAS PASSED INTO LAW IN 1985 IN ANTICIPATION OF THE STAGGERING FINANCING TASK FACING SOME OF OUR STATE'S INVESTOR-OWNED ELECTRIC UTILITIES IN COMPLYING WITH INEVITABLE FEDERAL CLEAN AIR LEGISLATION;

(C) A CLEAN COAL TECHNOLOGY STATUTE SIMILAR IN FORMAT AND RESULT TO THE CERTIFICATE OF NEED LAW. THIS STATUTE WAS USED TO CERTIFICATE THE NIPSCO-PURE AIR BAILLY GENERATING STATION PROJECT WHICH WAS DEDICATED LAST MONTH. AS A PERSONAL

NOTE, I MUST TELL YOU THAT IT GAVE ME GREAT SATISFACTION TO ATTEND THAT EVENT SINCE I WAS FIRST THE AUTHOR OF THE LAW IN THE LEGISLATURE AND THEN ONE OF THE PRESIDING COMMISSIONERS ON THE CASE WHICH AUTHORIZED THE PROJECT AFTER I WENT TO THE COMMISSION; AND

(D) A STATUTE PASSED IN 1991 ESTABLISHING A PRE-APPROVAL AND GUARANTEE PROCESS FOR CLEAN AIR ACT COMPLIANCE PLANS. THIS FIRST OF A KIND STATUTE WAS DEEMED NECESSARY BECAUSE OF THE TREMENDOUS IMPACT OF THE AMENDMENTS ON INDIANA'S COAL-BURNING ELECTRIC UTILITIES. PLEASE NOTE, HOWEVER, AS WE OFTEN DO AT THE IURC, THAT THIS AND THE OTHER PRE-APPROVAL TYPE STATUTES PUT A TREMENDOUS RESPONSIBILITY ON THE COMMISSION TO MAKE ACCURATE, REASONABLE UP-FRONT DECISIONS.

THESE FOUR STATUTORY INITIATIVES HAVE SOME COMMON FEATURES. EXCEPT FOR THE ENVIRONMENTAL COMPLIANCE PLAN LAW, EACH PROCEDURE IS REQUIRED OF THE UTILITY. IN ORDER TO BUILD GENERATING CAPACITY, BASELOAD OR PEAKING, CLEAN COAL OR OTHERWISE, THE UTILITY MUST OBTAIN PRIOR APPROVAL FROM THE COMMISSION. ALL OF THESE PROCEDURES INCLUDE PRE-APPROVAL OF THE UTILITY'S REASONABLE COST ESTIMATES AND GUARANTEED RECOVERY OF SAME TO THE APPROVED LEVELS. EACH PROVIDES THE OPPORTUNITY SHOULD THE UTILITY CHOOSE FOR THE COMMISSION TO REVIEW THE PROJECT OR PLAN ON AN ONGOING BASIS AND ADJUST THE APPROVED AND RECOVERABLE COSTS ACCORDINGLY. EACH HAS A WELL-DEFINED MODIFICATION PROCEDURE.

AND, EACH OF THESE STATUTES CONTAINS AN EXPRESSION OF THE LEGISLATURE'S PREFERENCE FOR THE USE OF INDIANA COAL IN THE INVOLVED FACILITIES. THE COMPLIANCE PLAN STATUTE EVEN REQUIRES THE UTILITY TO CONDUCT AND PLACE IN EVIDENCE AN ANALYSIS OF THE ECONOMIC EFFECT OF THE COAL-PURCHASING ASPECTS OF ITS PLAN ON THE SOUTHWESTERN INDIANA ECONOMY.

THE CONFLUENCE OF ALL THESE LAWS AND THE CLEAN AIR ACT AMENDMENTS HAS MADE THE ELECTRIC GENERATING CAPACITY PLANNING PROCESS IN INDIANA BOTH SIMPLE AND COMPLEX AT THE SAME TIME. SIMPLE IN THAT WHAT WAS ONCE A BASIC RESOURCE PLAN, AND THEN BECAME AN INTEGRATED RESOURCE PLAN HAS NOW EVOLVED INTO A FULL-BLOWN COMPLIANCE STRATEGY. IN ESSENCE THE ONLY PLAN THAT NOW MATTERS IN THE BIG PICTURE IS THE UTILITIES CLEAN AIR ACT COMPLIANCE PLAN. HOWEVER, WE HAVE SEEN IN THE PLANS FILED BY PSI ENERGY, SOUTHERN INDIANA GAS AND ELECTRIC COMPANY, AND INDIANAPOLIS POWER & LIGHT COMPANY THAT THE PLANS THEMSELVES ARE EXTREMELY COMPLEX AS THEY SEEK TO ANALYZE AND CHOOSE AMONG LITERALLY THOUSANDS OF COMPLIANCE ALTERNATIVES.

BECAUSE OF THE USE OF AND PREFERENCE FOR HIGH SULFUR COAL, IN INDIANA WHAT WE CALL THE "514" PLAN, NAMED AFTER SENATE BILL 514 WHICH WAS THE LEGISLATIVE VEHICLE FOR THE PRE-APPROVAL LAW, HAS COMPLETELY DOMINATED THE CAPACITY PLANNING PROCESS. THESE PLANS LAY OUT NOT ONLY THE UTILITY'S FUTURE IN TERMS OF EMISSION TRADING ALLOWANCES, DEMAND-SIDE MANAGEMENT, AND FUEL-SWITCHING, BUT CONTAIN

SPECIFIC DATES AND REFERENCES TO CONSTRUCTION OF BOTH PEAKING AND BASELOAD CAPACITY AND HOW SUCH CONSTRUCTION FITS IN TERMS OF OVERALL COMPLIANCE OPTIONS. IT IS NO EXAGGERATION IN INDIANA TO SAY THAT WHAT FORMERLY WAS THE CAPACITY PLANNING PROCESS HAS NOW BEEN SUPPLANTED BY THE COMPLIANCE PLANNING PROCESS.

*THE RECENT PSI CASE IS A PERFECT EXAMPLE OF THIS PHENOMENON.* ONE OF THE OVERRIDING ISSUES IN THAT CASE IS WHETHER AND TO WHAT EXTENT PSI CAN USE THE EMISSION TRADING MARKET TO DELAY THE NEED TO BUILD SCRUBBERS ON TWO OR MORE OF ITS EXISTING UNITS. LURKING BEYOND IS THE SAME ISSUE REGARDING THE CONSTRUCTION OF BASELOAD CAPACITY. IN THE POST CLEAN AIR ACT AMENDMENTS WORLD, IT IS IMPOSSIBLE TO SEPARATE CAPACITY PLANNING FROM COMPLIANCE PLANNING.

WE ARE HARD AT WORK ATTEMPTING TO CREATE A REGULATORY *FRAMEWORK FOR IMPLEMENTATION OF THESE STATUTORY INITIATIVES.* THE COMMISSION STAFF IS IN THE FINAL STAGES OF DRAFTING PROPOSED RULES AND REGULATIONS FOR BOTH INTEGRATED RESOURCE PLANNING AND THE RATEMAKING TREATMENT OF CONSTRUCTION-WORK-IN-PROGRESS FOR ENVIRONMENTAL CONSTRUCTION. WE HAVE ALSO ADOPTED AN INTERIM PLAN FOR EXPANSION OF GENERATING CAPACITY ON A STATEWIDE BASIS AND ARE WORKING TOWARD FINALIZING SAME EARLY NEXT YEAR. THE SUM TOTAL OF THESE EFFORTS SHOULD BE A CONCEPTUALLY-SOUND, PRACTICALLY POSSIBLE REGULATORY SCHEME WHICH HARMONIZES THE ABOVE-DESCRIBED FOUR STATUTES AND LAYS OUT A PATH WHICH INDIANA ELECTRIC UTILITIES CAN FOLLOW THROUGH THESE PERILOUS TIMES AND FOR MANY YEARS TO COME.

I HOPE THAT OUR INDIANA EXPERIENCE IS INSTRUCTIVE TO OTHER STATES LESS IMPACTED BY THE AMENDMENTS. WE BELIEVE THAT WE HAVE THE REQUISITE STATUTORY TOOLS AND TECHNICAL CAPABILITY TO ANALYZE THE COMPLIANCE PLANS PUT BEFORE US AND MAKE THE VERY DIFFICULT CHOICES NECESSARY TO COPE WITH OUR ELECTRICITY FUTURE.

# CLEAN COAL TECHNOLOGY: A REGULATOR'S VIEW OF DEVELOPING ISSUES

**By Dr. Bil Tucker**
**Chairman, Wyoming Public Service Commission**

I am pleased that many regulators share similar perspectives about both a high level of interest in Clean Coal Technology and many of the approaches and concepts regarding its use, especially since a number of them do not come from coal producing states. Although I happen to reside in such a state, Clean Coal Technology holds so much that is positive and promising in Clean Coal Technology that I need not -- and will not -- present a self-interested view. This paper expresses some of my views on the role of incentives in demonstrating and deploying advanced electric power technologies.

There are many ways to generate electricity; and all of them have certain unique benefits, shortcomings and costs -- some easily identified and agreed to, others not. As regulators look at the economics of generating the kilowatt-hours needed by this nation, there are two serious concerns which are always in mind. The first is the cost of producing and delivering the power; and the second is the societal cost of generation, including the costs of those environmental impacts which are now being recognized nationally. The federal Clean Air Act Amendments of 1990 addressed some environmental issues, primarily concerning $SO_2$, $NO_x$ and toxins, but they did not deal with such things as $CO_2$ or ambient heat output. States are also showing increased interest in the environmental costs of generation. As these and other emerging issues are addressed, we may expect generation costs to rise. While the full cost of dealing with them will not be known for many years, we can say with certainty that the economic costs will be substantial and that utility customers will pay the bill.

The nation has a large investment in thermoelectric generation, which serves us well. In order to effectively recoup this investment, we must act responsibly to make sure that coal fired generation remains a reliable, affordable and accepted resource. The Clean Coal Technology Program has identified improved methods of utilizing coal in electrical generation. Utilities are in the position of being able to select from clean coal options which can be applied at the tail end of the generation process, in the improvement of boiler combustion characteristics and to cleaning the fuel before it is burned.

In addition to bringing tested options to the utilities, the Clean Coal Technology Program can be of great benefit in hastening the deployment of advanced electric power technology. The planning considerations and uncertainties inherent in new technology are rightly approached with caution by utility planners and regulators. Demonstration and prototype projects can be prohibitively expensive for individual utilities and individual jurisdictions. It is appropriate, in any case where innovations can have positive national outcomes, for the federal government, as in the Clean Coal Technology Program, to undertake the partial funding of innovative developmental projects. In this way, the cost may be spread over the entire consumer population that stands to benefit from the developing technology.

Clean coal technology clearly holds out the promise of adding new environmental and efficiency benefits to proven and dependable generation resources, but it is necessary for state regulators to participate. Commissioners should remain open, if not proactive, with respect to new proposals by and on behalf of regulated utilities. I believe that individual state jurisdictions can and generally should be open to cooperating fully in the siting of projects and in the sharing of appropriately allocated costs, on an experimental or temporary tariff basis. Utility shareholders should also be expected to participate in the costs or funding requirements for these projects as the potential to benefit them is also great.

Next is the issue of valuation of environmental externalities and the implications this has for the development of the nation's energy supply. If regulators from economically powerful states place inappropriate and inaccurate environmental cost adders on potential out-of-state thermoelectric generation in the name of environmental progress, they will -- intentionally or not -- determine which resources will thrive, be developed and be purchased, regardless of how clean or cheap the resources are in fact. If arbitrary emissions costs are placed on out-of-state thermoelectric power, citizens of these states will be inappropriately deprived of available and reliable low cost power supplies which could have been responsibly selected and relied upon if local prejudices had not kept the energy from being priced consistent with its real cost. Out-of-state producers of environmentally responsible power will be arbitrarily excluded from the local market. Such a penalty would be just that -- a naked penalty that would not cure anything. Local air would not be made cleaner by wrongly excluding available clean out-of-state supply sources which produce no emissions within the recipient state's airsheds. Utility customers elsewhere would suffer from the costly forced inefficient utilization of baseload thermoelectric generating facilities.

States feeling the need to impute unsupported additional environmental costs to out-of-state power supplies should be careful not to manufacture costs which go beyond the actual costs of generation and transportation. For example, the existing costs of Wyoming thermoelectric power are *true* costs which already internalize the impact of strict environmental standards which have been in place for many years. Any unilateral assignment of additional costs -- especially those which are developed without reference to the easily determined actual costs or the environmental requirements of the producing state -- can be unreasonable, arbitrary and very counterproductive.

Certainly imposing externality costs on a particular generation technology will be reflected in the price which consumers pay. Misapplied externality valuation could result in the displacement of lower cost power by more expensive power through the economic distortion caused by arbitrarily attaching artificial rate significance to a power source. We must take a close and realistic look at the true impact of an environmental externality which is being evaluated. Politics and ecological fashion have no meaningful role to play in this inquiry. Regulators still must make hard and unfashionable inquiries. Any effect upon the environment and any other long chain of causes and effects must be firmly supported at every turn. If a firm link is established, then a true measurement of an actual external cost can and should be made. If a link is not substantiated, the externality is just that, external, and should be dismissed from the utility regulatory picture and given a decent burial by all jurisdictions concerned. It should not be allowed to have an unnaturally prolonged life of its own merely because it was the darling of a particular interest group. Regulators must remain the old curmudgeons they have always been. They must continue to insist on carefully researched, solid, factual evidence prior to changing the electricity generation fuel mix.

I have a certain nostalgic streak, as do most of us; but I do not want to see the United States return to the practice of studying in the kitchen by the light of an oil lamp. I am concerned that the cost of electricity could reach such a level that even the most fundamental units of consumption become unaffordable if costs find their way into rates without appropriate scientific and economic justification. In saying this, I am not issuing a novel challenge to environmentalists, of which I am one. The same requirement holds true for *every* cost which we are asked to add into rates. Regulators do not owe less to the public when environmental costs are being reviewed. We will serve best if we regulate dispassionately and with an eye for the truth and not the fashion. It should not have to be a courageous act to stand up for clean coal technology as it enters an exciting and innovative phase of its development.

What is needed is a realistic inquiry into the matter and a realistic assessment of all the implications. For example, if a clean coal technology application were to produce electricity more efficiently while at the same time reducing the production of potential pollutants, a regulator should be interested whether or not she subscribes to any particular nexus between potential pollutants and possible environmental effects.

There are, of course, implications for the Clean Air Act Amendments of 1990 for coal-based electric capacity planning. Some capacity enhancement projects will be driven by the requirements of the Clean Air Act Amendments. While we in Wyoming have only a small staff and limited resources to evaluate all of the various plans and methods proposed for Clean Air Act Amendment compliance, we have the opportunity to experience the effects of nearly every option, since Wyoming possesses an abundance of low sulfur coal and other hydrocarbons useful in generating electricity. We are sensitive to the need to encourage the production of all energy -- not just electricity -- in a manner which reflects the best available and most economical state-of-the-art technology consistent with preserving the high level of system reliability which has been demonstrated by thermoelectric generation over many years.

Many regions of the United States enjoyed comfortable energy and capacity reserves during the 1980's. However, the end of this surplus of generating capacity is at hand. An article in the May 1992 issue of *Electrical World* entitled "Waking Economy Bestirs Utility Planners" notes that "Coal fired construction is slated to increase a whopping 30%" between 1991 and 1992, that is, from $3.4 billion to $4.5 billion. Additionally, the article indicated that, between 1990 and 2000, 104,584 MW of new capacity is planned to enter service. Fifty one percent of that is to be utility-owned. The article breaks down the planned capacity by source. Fossil fuel steam is represented by 14,442 MW, 4,745 will be nuclear steam, 36,882 will come from gas combustion turbines, and 2,415 will be hydro. It appears, and rightly so, that coal will continue to figure prominently in the nation's energy future. Even if the current fuel of choice for planners may be natural gas, it is apparent that those who have pronounced coal generation dead are wrong.

Knowing the previously stated facts, one must ask how have the Clean Air Act Amendments affected utility generation planning? I believe that they have restructured the process utility planners will use to meet load growth and new peaks. To meet demand, utilities must now examine a broader spectrum of passive and active options from customer conservation and utility efficiency to the construction of new generating plants. The *Electrical World* article clearly indicates that utilities are looking to nonutility sources of supply for a significant portion of future

The Government Export Panel had no prepared papers but used a case study format for this session.

# INDUSTRY EXPORT PANEL SESSION

The Industry Export Panel will discuss: The need for industry and government cooperation; Industry's needs from government agencies; Industry's market priorities; and The role of electric utilities in project teams.

Moderator:
**Ben N. Yamagata**, Executive Director, Clean Coal Technology Coalition

*Mr. Yamagata is the Executive Director of the Clean Coal Technology Coalition. His legal practice encompasses federal and state legislative issues that deal with energy, environment, natural resources, international trade (technology transfer) and transportation-related matters. Special expertise includes representation before the legislative branch with respect to federal appropriations and energy-related tax issues as well as matters before Congressional committees with jurisdiction over energy, environment, natural resources and transportation matters. He has advised the $2.7 billion Department of Energy clean coal technology development program. Mr. Yamagata is Executive Director of the Clean Coal Technology Coalition and counsel to the Electric Transportation Coalition.*

Panel Members:
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# CLEAN COAL TECHNOLOGY
## A Private Sector Viewpoint

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# *CLEAN COAL TECHNOLOGY*
## *A PRIVATE SECTOR VIEWPOINT*

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**Electric Power Research Institute**

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Good afternoon. It is a pleasure for me to be here to discuss clean coal technology from the viewpoint of EPRI and its member utilities. I would like to discuss why we, as an Institute, enthusiastically support the large scale demonstration of advanced coal burning technologies.

**First,the role of EPRI is to provide improved technology to enhance the profitability of our members, with the emphasis on technology and profit**

The search for better equipment and better technology is a continuing priority for US utilities and their suppliers following the trail from the first steam turbine - driven generator in the early 1900s,to pulverized coal firing in the 1930s, supercritical steam conditions in the 1950s, fluidized bed combustion and coal gasification in the 1970s and 80s. Landmark advances are still being made in photovoltaics, fuel cells,combustion turbines, digital control systems,and environmental control equipment. But the idea of a utility as a profit making business has only lately been a key driver in the strategic planning of industry leaders. As with all businesses, success for the company follows a well defined path of innovation,technology leadership, productivity, and profit.So profit is strongly tied to technology and innovation and the future industry leaders in electric power production will be those who capitalize on proven advances, such as those now being demonstrated under the CCT program.

**Second, we acknowledge the importance and value of cooperative work with government bodies so as to leverage our R & D funding in key technology demonstrations.**

EPRI is a $500 million per year R&D organisation- the only one of its type in the world. It is unique,and a resource to the US utility industry that will never be duplicated. Yet in the high stakes of major construction EPRI can seldom, on its own, be the lead funding organisation. Therefore it is prudent for EPRI to participate with DOE and others in consortia to build and test major facilities such as coal gasification plants. It is gratifying to the Institute to see the progress being made in gasification following the successful construction and test of the 100MW Coolwater plant of Southern California Edison, built and tested by an EPRI-led funding consortium. We will continue in the future to use our R&D funds to support large technology demonstrations which offer significant future benefits for our members.

**Third, we perceive the future power generation business to be more international in nature, and so will seek cooperative agreements and technology transfer between other countries and the U.S.**

The role of EPRI as a "broker" for international technology advances is not new.Over the years we have successfully transferred to US power plants innovative ideas from Europe, Japan, and even Russia. Our staff continue to sift and evaluate new equipment design options which include at this time sliding pressure supercritical units, robotics, district heating technology, control measures for biofouling, and alternate fuels such as Orimulsion. EPRI is also active on broad issues like acid rain, global warming, technology for developing nations, and upgrading of Eastern European generating plants. EPRI staff are increasingly called upon for expert advice on such issues. Finally on this topic we have lately welcomed international affiliate members from England,Holland, Italy,Canada, and Australia, and have opened EPRI offices in Birmingham, England and Melbourne, Australia. We indeed are part of the international scene.

**Fourth, we see a strong domestic supply capability as being important to U.S. utilities.**

The strong links between the domestic suppliers and the US power industry have been maintained over the years even in the lean times of the last 10-15 years and have paid off for our industry. Landmark high efficiency plants such as Philo (Ohio Power), and Eddystone (Philadelphia Electric), would not have been possible without a joint agreement between utility and suppliers to advance the technology of fossil power plants. The same is true for the nuclear industry of the US. A network of supplier service shops across the country ensure that US utilities have access to the best and latest equipment and designs when maintaining or upgrading their units. This resource is going to become even more important with the aging of the fossil plants, since more than half will be 30 yrs old by the year 2000. So keeping our suppliers in the forefront of technology by soliciting their involvement in demonstration plants at home and commercial applications abroad is a strategic move for those utilities planning to be still "in the game" at the turn of the century. EPRI has close ties with all domestic ( and several overseas) suppliers of major equipment.

**Finally, we see certain environmental issues as global, which particularly need to be taken into account as the developing countries seek to expand their generating capacities.**

A new forecast by one US supplier concludes that the market for new generating equipment in the 1990s may total 1400 GW, based on a wordwide demand which will increase a modest 2.8%/yr. About 113 GW is needed in the US, 88 GW in Europe, 60 GW in Japan, Korea, and Taiwan, 45 GW in Latin America, 35 GW in former Iron Curtain countries, 26 GW in India, and a significant ammount in China and other developing nations. It is our opinion that new capacity should be designed and built as high on the learning curve as possible, This implies that clean coal and other emerging technologies should be the prime choice when considering new generation. The improved unit efficiencies and lowered air, water, and land emissions will greatly ease any future actions which may be necessary to protect our global environment.

EPRI has factored these five issues into our long term strategic R&D plan for the utility industry. We have worked cooperatively with DOE in its clean coal initiatives, and are currently participating in many of the DOE clean coal technology projects. As I noted earlier, we have expanded our membership to include utilities in Europe and in Asia, and we have participated, and will continue to participate in conferences and trade missions organized by DOE, DOC and others. Earlier this year I had the opportunity to attend a DOE clean coal conference in Hungary, and this summer participated in a DOE/DOC trade mission to Thailand. These activities underline the growing importance of countries whose added generation is likely to be largely based on coal.

One other cooperative venture of note is the utility partnership program, coordinated by USEA, where U.S.utilities agree to exchange technology with utility counterparts in Eastern Europe. Further there is a growing number of construction projects being carried out in various parts of the world by affiliate power producers, owned by U.S.utilities. Such activities emphasize the growing internationalization of the electric generating industry.

The DOE clean coal technology program which you have heard about this week has been instrumental in demonstrating at commercial sizes new technology in coal gasification, in pressurized fluidized bed combustion , and in advanced environmental control technologies for conventional pulverized coal power plants. It is certainly in the interests of our members, who will be using these technologies in the future, to see broad validation of the CCT products in many parts of the world. In our judgment, it is also important , as the underdeveloped countries seek to quickly increase their installed generating capabilities, that this is done using state of the art technology, instead of being based on equipment now seen as obsolete and often long superseded in Western countries. In this way we will be able to ensure that the quality of life for the world is enhanced while minimizing any concerns for the environment.

I look forward to discussing these ideas in more detail with you and with other members of this panel. Thank you.

**DOE CLEAN COAL TECHNOLOGY CONFERENCE**
**SEPTEMBER 23-24, 1992**
**INDUSTRY EXPORT PANEL**
**DEVELOPER NEEDS/RISK ASSESSMENT**

## *INTRODUCTION*

My thanks to the Department of Energy for this timely conference on clean coal technologies and the opportunity to participate in this Industry Export Panel. Our moderator, Ben Yamagata, asked that I address my remarks to: (a) the risks involved in applying clean coal technologies demonstrated and applied here in the U.S. to the power supply needs of emerging economies; and (b) to report on some recent efforts in Washington directed at exploration of ways to broaden the participation in the risks inherent in such projects and, thereby, improve the willingness of U.S. corporations to more aggressively pursue the development and implementation of projects in emerging economies which embody clean coal technologies (CCT).

A basic premise of these remarks is that there is a natural and a circumstantial confluence of CCT-exports with the current emphasis of private power as an advantageous concept for meeting the growing electric energy needs of emerging economies. The natural element of this confluence is that any firm with desire to present his CCT in the most favorable light wants not only to see his technology used in such projects but, also, to assure that it continues to perform well throughout the operational life of the project. This desire propels the project arrangement toward either or build-own-transfer (BOT) type project or some other similar arrangement whereby there is continuing direct involvement of the technology supplier in the longer term operation and maintenance of the power generation facilities. The circumstantial element of this confluence is one simply of concurrent timing i.e., the recent readiness of CCT's for commercial application -- and the recent emphasis of the OECD nations to the emerging-economy counties that the supply of reliable electricity supply can be more efficiently financed and provided by private sector entities then by the public utilities of many of these countries.

Also, be forewarned. I am one of those "Washington, D.C. people" and these remarks will reflect that perspective. However, as you will see, I believe there is a positive climate in the government and international communities of Washington, D.C. for measures that could help U.S. industry use CCT's to increase the export of U.S. equipments and services.

One brief caveate. The ideas presented in these remarks are conceptual. They have not withstood the test of argument as to their attributes or their practicability with project developers, financiers, or government assistance agencies.

## THE CHALLENGE

The following describe some basic characteristics of the challenge to be addressed.

- o The pace at which economic development can be achieved in most emerging economies is dependent upon the ability to bring into being necessary economic infrastructure such as reliable electricity supply. Therefore, electricity supply facilities will, in most countries, be a high natural priority.

- o The high resource requirements of electricity supply facilities, both in terms of their large foreign exchange requirements and experienced technical and project management personnel requirements, can seriously limit the national capability to expand this element of its economic infrastructure.

- o The historic character of electricity supply projects in many emerging economies includes:

  - -- they are planned and implemented by public sector utilities;
  - -- they involve large foreign exchange components both in equipments and services;
  - -- they involve high risks and have frequently experienced large cost overruns; and,
  - -- growing environmental concerns create increased incentive for application of advanced technologies in electric power facilities.

- o Many countries are examining or initiating an historic change in the organizational structure of their electricity supply sector in response to the recent strong encouragement from the OECD nations noted earlier regarding privatization and support of that policy by IMF and the multilateral-finance-institutions (MFI's).

Initiatives to utilitize CCT's as an avenue to increase exports of U.S. equipments and services to emerging economics exercerbates the complexity of this challenge. Coal is a highly varied and complex fuel. There is a large array of technology options which need to be examined in the selection of a preferred approach for the use of coal in a national electric sector plan. Application of advanced technologies in these nations involves all aspects of adapting and introducing advanced technologies into a new physical and cultural setting.

## RISK PARTICIPATION A CRITICAL CORE ISSUE

I intend to focus my remarks today on risk participation as a critically important core issue in forming effective arrangements for development and implementation of private-sector funded, clean-coal-technology projects in emerging economies. First some basic facts:

- o Private sector involvement does not change the total risks involved. It only changes the assignment of risks among the various project participants.

- Equitable, economically efficient assignment of risk participation can be critical to the economic feasibility and the ability to finance projects.

- The risks inherent in any major electricity supply project are frequently insufficiently defined and understood by host country officials and utilities. Nor are the value of those risks in terms of their costs or their impacts well understood since in the previous public-financing-mode for such projects there was no incentive (and frequently a disincentive) to openly address and place a value on inherent risks.

- There is a natural aversion by all parties toward risk participation.

In this light, finding mutually acceptable arrangements for economically efficient risk participation could importantly affect the degree to which privately owned power supply and the use of clean coal technologies can be widely applied to provide reliable electricity supply in emerging economies.

## RISK SPECTRUM

A brief diversion is needed at this point to provide primer-type information on the spectrum of risks which need to be kept in mind in the remainder of these remarks.

There are three primary time phases of the risks involved. First, those during the project definition/project development phase. Second, those during pre-completion of the facility e.g., risks during design, procurement, construction activities. Third, those post completion of the facility e.g., in facility O&M, fuel supply, revenue generation, etc.

There are different sources or types of risks. Some are rooted in the project authorization and regulatory approvals of the project. National policies regarding facility ownership, environmental goals or use of indigenous fuels can generate risks. Economic regulation of product prices, rates-of-return, taxes, and local labor rules can introduce risks.

Regulatory permits on site use, facility effluent, water availability, waste disposal, etc., are the source of widely recognized risks.

Commercial risks include those related to technology readiness/adaptation/appropriateness, project costs, schedule and procurements, facility design, design change and construction activities.

There are always the risks of accident or natural catastrophe which need to be considered. And, there are risks rooted in the national economic climate or political stability of the country which can include, for example, national policy/economics/institutional changes, expropriation of owned facilities and currency exchange rate fluctuations.

Also there is the need to rank various risks on the basis of their probability of occurrence and the seriousness of their impacts on project activities, economics, or feasibility.

## RISK ASSIGNMENT OBSERVATIONS

Building on those fundamentals, I offer some observations regarding risk participation attitudes and opportunities whereby the foundation for well conceived private power projects using clean coal technologies might be improved. The first five observations are directed at the concept of "economic efficiency" of risk participation.

1. It seems fully appropriate and acceptable that the project developer/contractor team take on commercial risks and other risks which he has the ability to control. Assignment of low probability/high impact risks to the developer/contractor team ably illustrates the concept of economic efficiency. The developer/contractor team would cover such risks by contingency provisions or insurance and, if the impact threat is large, this could be involve very high cost. If the risk did not occur, the cost for risk coverage would, nonetheless, remain and could seriously impact project economics. This would, therefore, be economically inefficient.

2. The host country government/utility should be willing to be assigned risks over which he has more control, more experience with the cultural/institutional setting, and more ability to expedite resolution. This could include high probability, low impact risks such as site availability/approval, fuel supply arrangements, local cost/price escalation, currency convertibility etc.

3. More effort needs to be directed at assignment of other risks on a least cost or optimal economic efficiency basis among other project participants including equity investors, commercial financiers, multilateral financiers, host government agencies, export credit agencies, and bilateral development donors. I see great opportunity for innovation in this regard, the results of which could critically affect the degree of success in providing projects of this type.

4. No-recourse or limited-recourse project financing needs to be viewed simply as another form of risk participation. It can importantly affect the project developer's ability to arrange adequate financing. It can also be very important to the host country government as it enables off-balance-sheet financing of economic infrastructure projects.

5. Equitable, economically efficient risk assignment needs to consider:

    - the limits on each party's ability to assume that risk;
    - the value, probability and impact of the risk and its coverage on project feasibility and economics;
    - the time aspects of risk occurrence;
    - prospects for arranging a broadened base of risk sharing;
    - the effect of risk assignment and risk sharing on the functional project arrangement and security package.

6. Our panel moderator, Ben Yamagata, and I have over the past few months been "testing the water" so-to-speak of attitudes toward exploration of new risk participation concepts and the willingness to consider changes of traditional risk participation concepts, groundrules and processes. Exploratory contacts have been made with: the U.S. Agency For International Development, U.S. Department of Energy, U.S. Export/Import Bank, the World Bank, the International Finance Corporation, host government representatives, U.S. congressional staff, potential project developers, and U.S. equipment/service suppliers. We have found consensus among all on the need to carry on more indepth interactive discussion of this topic. Most importantly, there appears to be an openness to examine changes in their traditional processes and procedures if it can be shown they are needed in order to:

   - avoid high cost impacts of risk assumption;
   - justify the use of the private sector ownership/financing concept; or,
   - enable private developer/contractor teams to aggressively pursue development of such project arrangements and invest corporate resources in the development and implementation of economic infrastructure projects.

7. In the conduct of this mutual exploration process, I see a need for what I would label "aggressive imagination" and I offer the following as a menu of potential topics which merit exploratory discussion.

   - Broaden the scope of project feasibility study to encompass more of those project development activities which are crucial to bringing into being a workable arrangement for project implementation;
   - Examine means for effective donor assistance for first-time or one-time technology adaptation/application costs;
   - Broaden the scope of technology transfer activities eligible for multilateral or bilateral donor assistance;
   - Examine the use of debt-equity swaps to apply to local costs or equity participation;
   - Provision of economic awards for sustained superior environmental performance;
   - Negotiate bilateral investment agreement provisions that would lessen the impact of taxes on project costs/economics;
   - Include in allowable project costs or consider provision of donor assistance for "peripheral project requirements" such as roads, community services/facilities, fuel delivery system improvements, etc.; and,
   - Examine loan guarantees or other mechanisms to effectively leverage the financial support provided by bilateral/multilateral project finance agencies.

8. The mutual exploration process would need to examine these and other ideas with aggressive imagination to see how they measure up to the "5-A test"; i.e.

   - Would the risk participation measures be APPLICABLE to the project?

- Are the risk participation measures APPROPRIATE to the project institutional/cultural setting and other project requirements?
- Would such risk participation ACTUALLY ASSIST the formation and implementation of the project?

If the concepts passed those tests, then, and only then, would one address:

- Might such risk participation be made AVAILABLE to the project? The exploration discussions must avoid the too-easy-decision to discard a proposed form of risk participation on the basis that it is not typically or has not previously been done. The discussion must examine the capability of the proposed risk participation measure to help make the projects more possible and leave to others the specifics of how to make them available.

## CONCLUSIONS

First, the situation is ripe for mutual exploration of risk participation measures that just might importantly affect the joint capabilities to make privately developed electricity supply projects using advanced technologies more doable in emerging economies.

- There continues to be strong policy level support for the concept of privatization as an effective means for providing expanded economic infrastructure capabilities for emerging economies.

- The staffs of organizations such as World Bank, IFC, USAID, and DOE have been directed to define and implement effective processes for contributing to the achievement of this goal.

- The search for effective mechanisms by those organizations continues. Industry input to their thinking would be welcomed. All see the need for more dialogue and the prospect of mutual benefits.

- There is strong policy level support in the U.S. Government to increase exports of U.S. equipments and services to other countries.

- There is broad recognition within the export promotion community that exports based on CCT's demonstrated in U.S. facilities offers an attractive opportunity for increased export of U.S. equipments and services.

- An openness exists toward change of traditional methods and processes if one can show that such changes are necessary to better achieve the policy-level goals.

Second, industry can be the essential and effective catalyst to initiate and formulate this dialogue directed at mutual exploration for effective risk participation measures. And fortunately, there is activity underway in this direction. Stay tuned for further developments.

# ASIA'S COAL AND CLEAN COAL TECHNOLOGY MARKET POTENTIAL

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## Introduction

The Asian region is unique in the world in having the highest economic growth rate, the highest share of coal in total primary energy consumption and the highest growth rate in electricity generation capacity. The outlook for the next two decades is for accelerated efforts to control coal related emissions of particulates and $SO_2$ and to a lessor extent NOx and $CO_2$. Only Japan has widespread use of Clean Coal Technologies (CCTs) however a number of economies have plans to install CCTs in future power plants. Only CCTs for electricity generation are discussed, and are defined for the purpose of this paper as technologies that substantially reduce $SO_2$ and/or NOx emissions from coal-fired power plants.

## Asia's Coal Future

Asia-Oceania leads the world in dependence on coal with almost half of it's energy requirements (48 percent) supplied by coal compared to less than a quarter (22 percent) for the rest of the world. The outlook for Asia

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[1] *Dr Johnson is head of the Coal Project and Dr. Li is a Research Fellow in the Coal Project.* *Acknowledgement is given to Mr.Scott Long, Research Fellow, for his assistance in the preparation of this paper, and to the U.S. Department of Energy's Office of Fossil Energy for their financial support of the East-West Center's CCT research.*

over the next two decades is for both coal production and consumption to increase by more than a billion metric tons (tons) per year and coal imports to increase by 178 million tons to about 350 million tons by 2010. Steam coal's share of imports is projected to increase from 50 percent today to more than 75 percent in 2010. Australia will remain the dominant coal exporter to Asia over the 1990-2010 period, however is expected to loose a modest share of the export market to Indonesia and possibly China. North American exports of both coking coal and steaming coal to Asia will face increased price competition, resulting in an erosion of North America's share of the Asian market. North America's role as a swing supplier of steaming coal to Asia will continue for the foreseeable future. Strategic and political considerations, particularly in Japan, will ensure that western U.S. exports are maintained at a few million tons per year. In addition, there may be significant export potential for multipurpose coals (low sulfur coals that can be used as coking, PCI and steam coals).

## Determinants of Coal in Asia's Future[2]

Important factors determining changes in coal production, consumption and trade in Asia are: (1) government policies, (2) economic and electricity growth in Asia, (3) energy options, (4) competition and prices, (5) strategic factors, (6) environmental trends. These factors are briefly discussed below.

(1) Government Policies. Most governments in Asia have substantial influence on energy choices through policies and recommendations made at the central government level. This is particularly true in electricity generation, because the majority of electric utilities are state corporations and closely follow government policies and directives. Most governments in Asia consider coal a very important part of their energy mix. The trend is away from providing high subsidies to maintain domestic production.

[2]This section is a revised section from "Asia's Coal Future to 2010", Johnson, 1992.

(2) Economic and Electricity Growth in Asia. The growth rate in electricity consumption is higher than gross domestic product (GDP) rates in most Asian economies, but is gradually moving toward the GDP growth rate. Tables 1 and 2 show GDP and electricity growth rates for Asian economies in the 1980s, with projections to 2010. Both GDP and electricity growth rates in most Asian economies are typically 2-3 times as high as both the world average and most industrialized economies.

(3) Energy Options. Most Asian economies have limited amounts of oil and gas, and have policies to promote the use of thermal coal for electricity generation. Coal is abundant in Asia and is the most abundant energy resource in Australia, China, India, Russia, Vietnam and probably Mongolia.

After the second oil crisis in 1979, there was a shift toward increased steam coal use for electricity generation in Hong Kong, Indonesia, Japan, South Korea, Philippines, Taiwan and Thailand. The trend toward greater coal use in electricity generation is projected to continue over the 1990-2010 period. However, where sufficient natural gas is available at competitive prices, it is the preferred fuel. In particular, Malaysia will continue to rely on its abundant natural gas reserves to meet most electricity generation needs. In addition, natural gas is expected to compete with coal in Hong Kong, Indonesia, selected areas of southern China, Thailand, and in Vietnam.

(4) Competition and Prices. The rapid growth in the demand for internationally traded steam coal has been more than matched by increased supplies from both traditional coal producing countries and new suppliers. A decade ago many forecasts indicated increasing prices for steam coal. However, Figure 1 shows that the trend in c.i.f. steam coal prices in constant 1990 dollars for the world's largest coal importer, Japan, was strongly downward over the past decade. This downward trend has continued to the present (mid-1992) with spot prices well below the 1990 level.

Figure 1 also shows that the trend in the price of U.S. steam coal exports has been moving closer to the weighted average price of steam coal from other countries. The decrease in spread of steam coal prices results from increased competition among sellers, improved economics of U.S. western coal exports, and less premium being paid to diversify sources of supplies.

(5) Strategic Factors. Strategic factors are particularly important to Asian economies. Specifically, most major coal importing economies in Asia indicate a goal of diversifying sources of supply of coal. Asian governments are reluctant to state an upper limit to the share of coal imports from any country. However, most governments prefer to keep imports from any one source below about 50 percent.

(6) Environmental Trends. The impact of environmental trends on coal use can be divided into two categories. The first category includes traditional emissions (particulates, $SO_2$ and $NO_x$) that can be controlled with existing technologies. All Asian economies are projected to substantially reduce these pollutants as they expand and modernize their power plants. The second category of emissions are greenhouse gases, dominated by $CO_2$, that cannot be readily controlled with existing technologies. The present strategy of most Asian economies to control greenhouse gas emissions is to promote greater efficiency in power generation and energy use.

The developing economies of Asia have not altered their plans with respect to future coal use because of concerns about coal's contribution to greenhouse gases because, in most cases, there are no alternatives that would not slow economic growth. Economic growth remains a high priority throughout Asia, even at the expense of some deterioration of the environment. Japan is the most likely major coal consumer in the region to follow a strategy to substantially reduce coal consumption in order to control greenhouse gas emissions.

## Coal Projections for Asia: 1990-2010

Table 3 shows the expected growth in consumption of the major coal consumers in Asia over the 1990-2010 period. India and China are expected to maintain their 80 percent share of the total coal market for the next two decades. The number of Asian economies consuming 20 million tons or more per year will increase from six economies in 1990 to ten in 2010 with Indonesia, Philippines, Taiwan and Thailand joining the list.

Table 4 shows net trade of coal over the 1990-2010 period. Net coal imports to the Asian region are projected to gradually increase from 34 million tons in 1990 to 55 million tons in 2010. As a percentage of imports, the share of imports into the region is projected to decrease from 20 percent in 1990 to 16 percent in 2010. This relative decline in share of imports is because the growth in imports is mostly for lower priced steaming coal, which can be supplied more competitively from producers within the region.

Figure 2 shows the trends in steam and coking coal imports of Asian economies from 1980 to 1990, with projections to 2010. Steam coal is now approximately equal to coking imports, but as shown in Figure 2, steam coal is expected to account for all net increases in coal imports to 2010.

## Market Potential for Clean Coal Technology in Asia

The following projections of the size of the CCT market in Asia in 2000 and 2010 are preliminary and speculative, and only are intended to highlight the potential important market opportunities in the region.

The potential for CCTs is broadly related to per capita income levels of economies. The highest income Asian economy, Japan, has already installed flue gas desulphurisation (FGD) to control $SO_2$ emissions, plus selective catalytic reduction (SCR) to control NOx emissions. Japan is the leader in Asia in development of the next generation of CCTs (i.e. IGCC and PFBC). The middle to upper income economies (Hong Kong, South Korea, Taiwan and Thailand) appear to be most interested in FGD technologies, and plan to install these on most new capacity. The lower income economies (China, India, Indonesia and the Philippines[3]) are primarily interested in lower cost options to control emissions (fuel switching, burning low sulfur coal (plentiful in some areas), and probably CFBC with desulfurizing agents.

The Japanese CCT market is nearly saturated, and is difficult to penetrate by U.S. firms, however is the most promising market for the next generation of CCTs (i.e. IGCC and PFBC). The middle income economies are the best markets to target in the 1990s because they are just beginning to switch to FGDs. The low income economies are the most speculative because of their present reluctance to introduce CCTs which will add significantly to investment costs. However, some of the low income economies have the greatest long term potential, and should not be ignored in developing CCT export strategies.

Turning to forecasts for Asia, Figure 3 shows total GW of coal fired capacity for 1990 with projections for 2000 and 2010. The 1990 capacity of 172 GW is projected to grow at 7.7 percent per year to 362 GW in 2000, then slow to an average of 6.0 percent per year reaching 648 MW in 2010. These projections are probably only accurate to within about $\pm 10$ percent.

Figure 4 shows the country shares of coal-fired capacity in 1990, with China and India accounting for about three quarters of total capacity. China and India are expected to retain about three-quarters of total capacity to 2010, with Japan's share decreasing from 12 to 7 percent as coal-capacity in other economies grow at faster rates.

Our preliminary projections are for the Asian market for CCTs to increase by about 45 GW in the 1990-2000 period, and by about 105 GW from 2000-2010 for a total increase of about 150 GW over the 1990-2010 period. Estimates of CCT market shares among economies are quite speculative. However, our analysis indicates that market shares could change dramatically between the first and second decades of the forecast period. As shown in Figure 5, in the 1990s three middle-upper income group economies (Hong Kong, South Korea and Taiwan) are projected to

[3]The Philippines can also be classified as a lower-middle income economy.

account for the largest share of new CCT capacity (40 percent) followed by Japan (32 percent). However, as shown in Figure 6, we believe that a substantial shift will occur during the 2000-2010 period with China accounting for the largest share of new CCT capacity (45 percent).[4] This projected shift toward CCTs is not reflected in present plans in China, but is based on our assessment of future shifts in Chinese policies and strategies. The following brief discussion provides the basis for our optimistic projections for China.

China's Potential Clean Coal Technology Market. China relies on coal for about three-quarters of its primary energy needs. The more than one billion tons of annual coal consumption in China makes it the largest source of $SO_2$, NOx and $CO_2$ emissions in Asia. China accounted for about two-thirds of total $SO_2$ and half of NOx and $CO_2$ emissions in Asia in 1987 -- the most recent year in which complete figures are available (Kato et al., 1991).

China's top priorities in the electricity sector are increasing efficiency and reducing particulate emissions from coal burning followed by $SO_2$ with lowest priority given to reducing $CO_2$. Because increasing efficiency reduces $CO_2$ emissions, Chinese officials point out that they are reducing greenhouse gas emissions through this strategy. More important to Chinese energy planners is to alleviate China's electricity shortages. Increased efficiency is seen as one of the key elements in their strategy to close the gap between electricity supply and demand.

China is not likely to select CCTs that result in reduced efficiencies. Second, China is unlikely to adopt CCTs that are either not widely used commercially or have significantly higher capital costs. This eliminates technologies under development, including IGCC and PFBC, and probably limits the application of FGDs for at least the 1990s.

About 40 percent of China's electricity consumption is highly concentrated in the six areas shown in Figure 7, representing only five percent of the area of China. These areas have high levels of coal related

[4]It is possible that China's shift toward CCTs could be delayed by 5 years (2005-2015) but is unlikely to be delayed by more than 10 years (2010-2020).

pollution and more effective and stringent controls are highly likely in order to reduce coal related emissions. Much of the coal related pollution comes from home heating with coal (10-20% efficiencies) and small industrial boilers. Locating power plants away from cities can only have a moderate direct impact on coal related emissions because of home use of coal and industrial boilers. However, location of co-generation power plants with $SO_2$ control equipment in cities and industrial areas can achieve the two major goals of increased efficiency and reduced pollution. Co-generation could provide both electricity, and steam for home heating and industrial uses, and raise overall energy efficiencies above 70 percent. This is the kind of "win-win" strategy option that we believe will have high appeal to Chinese planners.

Chinese government policies are expected to change toward encouraging appropriate CCTs within a few years. We believe there will be substantial potential for non-state controlled companies to participate in co-generation plants. CFBC plants are the type of plants that appear to have considerable promise because they are competitive at the smaller plant scales common in China, have considerable flexibility among fuel qualities, and emissions can be controlled at modest cost.

## Who Will Supply CCTs to Asia?

There will be numerous sources of CCTs, including a number of economies in Asia. However, the two leaders in CCTs, Japan and the United States, appear to be a natural match for cooperation and joint venture arrangements in introducing CCTs to Asia. During this period of "Japan Bashing" it is easy to overlook opportunities for U.S. and Japanese companies to cooperate to their mutual advantage. The differences in (i) the Japanese and U.S. CCT programs, and (ii) the understanding and access to Asian markets might be turned into benefits for industries in both countries.

First, there are the following important differences in the development and introduction of the CCTs in the two countries[5].

[5]Dr. Akira Kinoshita, Assistant to the President of the Electric Power Development Corporation in

(1) Japan launched its CCT program in the late-1970s to install FGD before other countries, including the United States, believed that the additional costs of $SO_2$ control were warranted. As a result Japan leads the world in emission control on its coal-fired power plants -- all have advanced FGD systems, and most have SCR control systems.
(2) Japanese companies were able to pass the costs of emission control technologies on to consumers, whereas in the United States the Public Utility Commissions (PUCs) have limited the ability of utilities to pass on all costs of environmental control equipment in a timely manner.
(3) The ability of utilities to more readily pass on costs to consumers in Japan has resulted in less effort to control costs, and more attention to introducing the most advanced technologies, often at much higher costs. In contrast, both the PUCs and U.S. environmental legislation encourage industry to select the lowest cost options to meet emission limits.
(4) The U.S. government funded CCT program is much larger than the Japanese program, and encourages more competition among more technologies and more companies. The Japanese program encourages more cooperation on a smaller range of technologies.

The consequences of the above generalizations (there are exceptions) are that U.S. CCTs are likely to be more competitive than Japan's CCTs, and therefore have greater economic appeal to other Asian utilities.

The second important factor in succeeding in the Asian market is having an equal or superior knowledge of Asian business practices, and an effective organizational structure to capitalize on this knowledge. Here Japanese industry excels over U.S. industry (there are exceptions). The reasons for the Japanese advantage are complex, but appear to be heavily influenced by four factors. First, Japan is an Asian culture, and has a better understanding of other Asian cultures. Second, the Japanese government's industrial strategies and those of industry are much more closely linked. This may provide a particular advantage in penetrating largely state

Japan, is the source of information on points 1 and 2. However, any errors in interpretations are those of the authors and not Dr. Kinoshita.

controlled Asian electric utility markets. Third, the Asian market is geographically on Japan's doorstep, and therefore receives a higher priority. Finally, Japan has a longer term time horizon in its industrial strategies, which appear particularly suitable to the infant CCT market in Asia.

In summary, the U.S. appears to have the competitive CCT technology edge, whereas Japan has the business culture and strategy edge in Asia. Both countries appear to need each others cooperation to achieve maximum benefit from the evolving CCT markets in Asia. The environmental problems in Asia are so large that neither country can meet the CCT needs of Asia alone. The potential exists for a larger total CCT market in Asia through cooperation and joint ventures between U.S. and Japanese companies.

## Conclusions

The main theses of this paper are that major increases in coal consumption will occur over the 1990-2010 period, and this will be accompanied by major increases in coal related pollution in some Asian economies. Coal fired electricity generation is projected to grow at a high rate of about 6.9 percent per year over the 1990-2010 period. CCTs are projected to account for about 150 GW of new coal-fired capacity over the 1990-2010 period or about one-third of all new coal-fired capacity. A speculative conclusion is that China will account for the largest share of CCT additions over the 1990-2010 period. Both the U.S. and Japan have comparative advantages that might be combined through cooperation and joint ventures to gain a larger share of the evolving CCT market in Asia.

Table 1

## Average Annual GDP Growth Rates

(Percent)

| | 1980-1990 | 1990-2000 | 2000-2010 |
|---|---|---|---|
| China | 9.7 | 8.5 | 6.5 |
| South Korea | 8.2 | 8.0 | 6.0 |
| Taiwan | 8.0 | 7.1 | 5.5 |
| Hong Kong | 7.5 | 5.5 | 6.0 |
| Thailand | 7.3 | 8.0 | 6.0 |
| Pakistan | 6.6 | 6.1 | 5.5 |
| India | 5.8 | 4.6 | 5.0 |
| Indonesia | 5.8 | 6.7 | 6.0 |
| Malaysia | 5.8 | 7.0 | 6.0 |
| Japan | 3.9 | 3.7 | 3.3 |
| Philippines | 1.9 | 3.4 | 4.5 |

Source: Coal Information 1991; International Financial Statistics; Project LINK, 1992; and EWC Coal Project estimates.

Table 2

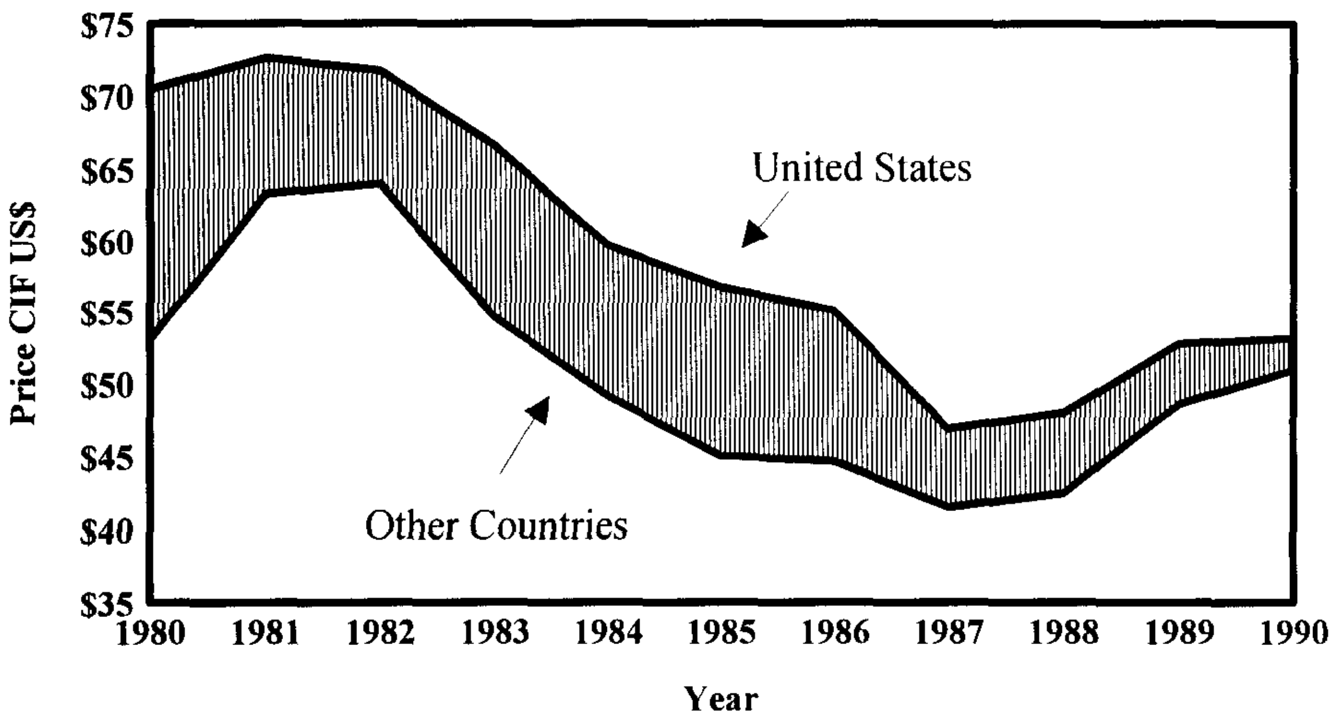
## Average Annual Electricity Growth Rates

(Percent)

| | 1980-1990 | 1990-2000 | 2000-2010 |
|---|---|---|---|
| Indonesia | 14.2 | 10.0 | 7.2 |
| Pakistan | 11.9 | 8.5 | 6.0 |
| South Korea | 11.1 | 8.0 | 6.0 |
| Thailand | 10.8 | 9.5 | 6.0 |
| India | 9.1 | 6.0 | 5.0 |
| Malaysia | 8.6 | 7.7 | 6.0 |
| Hong Kong | 8.5 | 5.5 | 6.0 |
| Taiwan | 8.3 | 7.0 | 5.0 |
| China | 7.7 | 8.1 | 6.5 |
| Philippines | 4.3 | 5.2 | 5.0 |
| Japan | 3.7 | 3.3 | 2.6 |

Source: Coal Information 1991; International Financial Statistics; and EWC Coal Project estimates.

**Comparison of the Average CIF Prices of U.S. and Non-U.S. Steam Coal Exports to Japan**




Source: EWC Coal Project, 1992.

Figure 1

Table 3

## Coal Consumption in Asia[1]: 1990-2010

(Million metric tons)

| Economy | 1990 | 2000 | 2010 | Increase 1990-2010 |
|---|---|---|---|---|
| China | 1,063 | 1,365 | 1,655 | 592 |
| India | 205 | 360 | 575 | 370 |
| Japan | 113 | 142 | 151 | 38 |
| Australia | 57 | 66 | 85 | 28 |
| Korea (North) | 52 | 65 | 75 | 23 |
| Korea (South) | 43 | 56 | 60 | 17 |
| Taiwan | 19 | 35 | 57 | 38 |
| Hong Kong | 10 | 13 | 16 | 6 |
| Indonesia | 7 | 25 | 45 | 38 |
| Vietnam | 4 | 8 | 17 | 13 |
| Philippines | 3 | 13 | 22 | 19 |
| Thailand | 1 | 6 | 25 | 24 |
| Other | 10 | 16 | 22 | 12 |
| Total | 1,587 | 2,170 | 2,805 | 1,218 |

[1] Asia includes the SW Pacific but excludes the Russia; 1990 figures do not include stock adjustments; excludes lignite. EWC Coal Project projections, 1992.

## Table 4

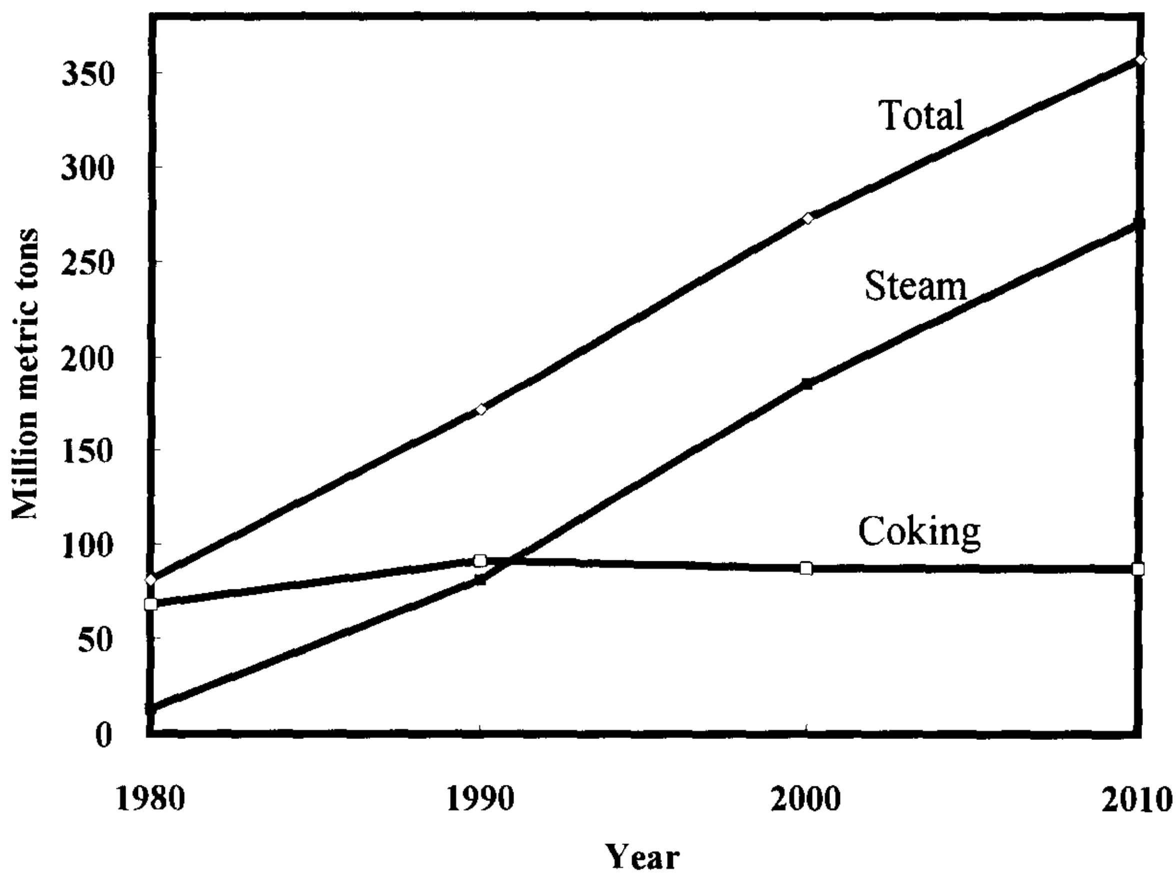
## Coal Trade in Asia[1]: 1990-2010

(Million metric tons)

| | 1990 | 2000 | 2010 | Change 1990-2010 |
|---|---|---|---|---|
| Net Exporters | | | | |
| Australia | 106 | 150 | 200 | 94 |
| China | 17 | 35 | 45 | 28 |
| Russia (Eastern) | 10 | 11 | 13 | 3 |
| Indonesia | 4 | 25 | 30 | 26 |
| Vietnam | 1 | 4 | 7 | 6 |
| Net Exports | 138 | 225 | 295 | 157 |
| Net Importers | | | | |
| Japan | 105 | 141 | 150 | 45 |
| Korea (South) | 22 | 43 | 53 | 31 |
| Taiwan | 19 | 35 | 57 | 38 |
| Hong Kong | 10 | 13 | 16 | 6 |
| India | 4 | 15 | 20 | 16 |
| Korea (North) | 3 | 5 | 5 | 2 |
| Philippines | 2 | 9 | 17 | 15 |
| Thailand | 1 | 6 | 25 | 24 |
| Other | 6 | 6 | 7 | 1 |
| Net Imports | 172 | 273 | 350 | 178 |
| Net Trade | -34 | -48 | -55 | -21 |

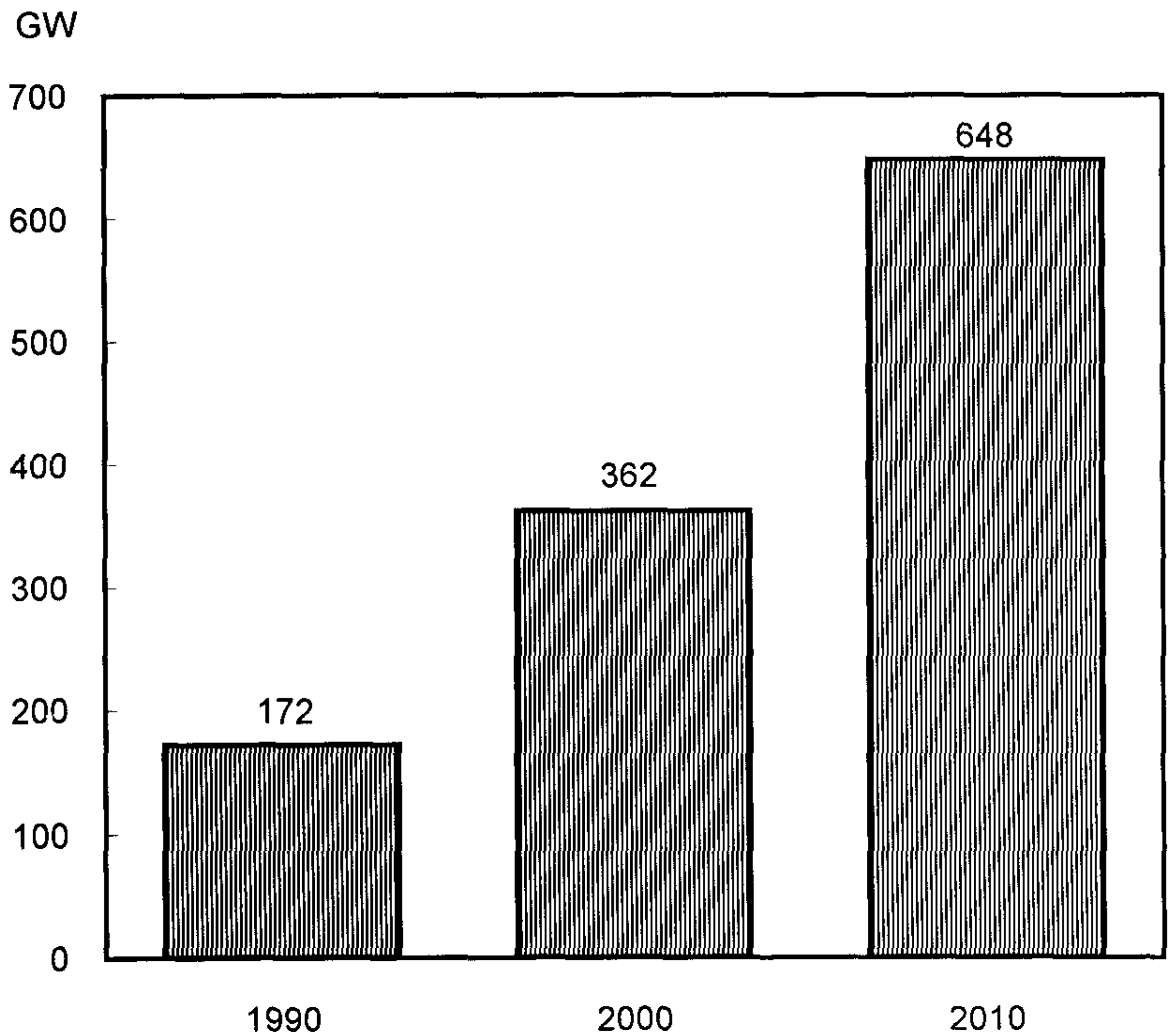
[1] Asia includes the SW Pacific; excludes lignite. Includes exports from eastern Russia into the Pacific, but Russia is not included in the production and consumption tables. EWC Coal Project projections, 1992.

## Steam and Coking Coal Imports of Asia 1980-1990 with Projections to 2010




Source: EWC Coal Project , 1992.

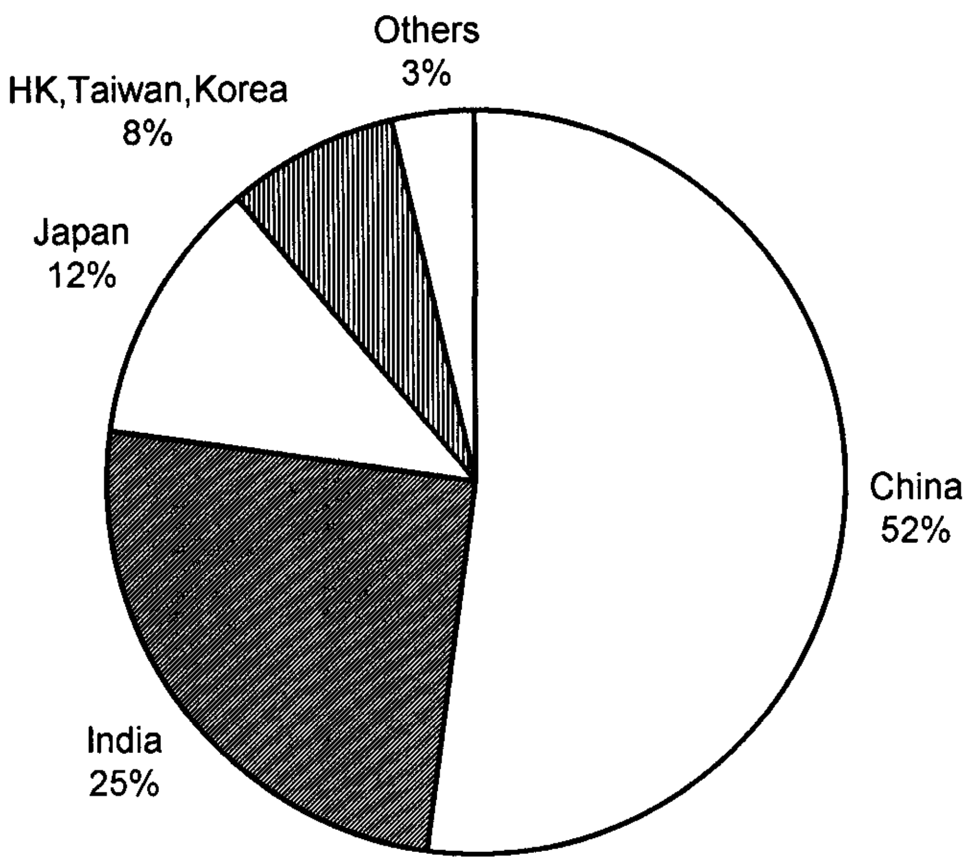
Figure 2




**Coal-fired Capacity in Asia in 1990 with Projections to 2000 and 2010.**

Source: EWC Coal Project, 1992.

Figure 3

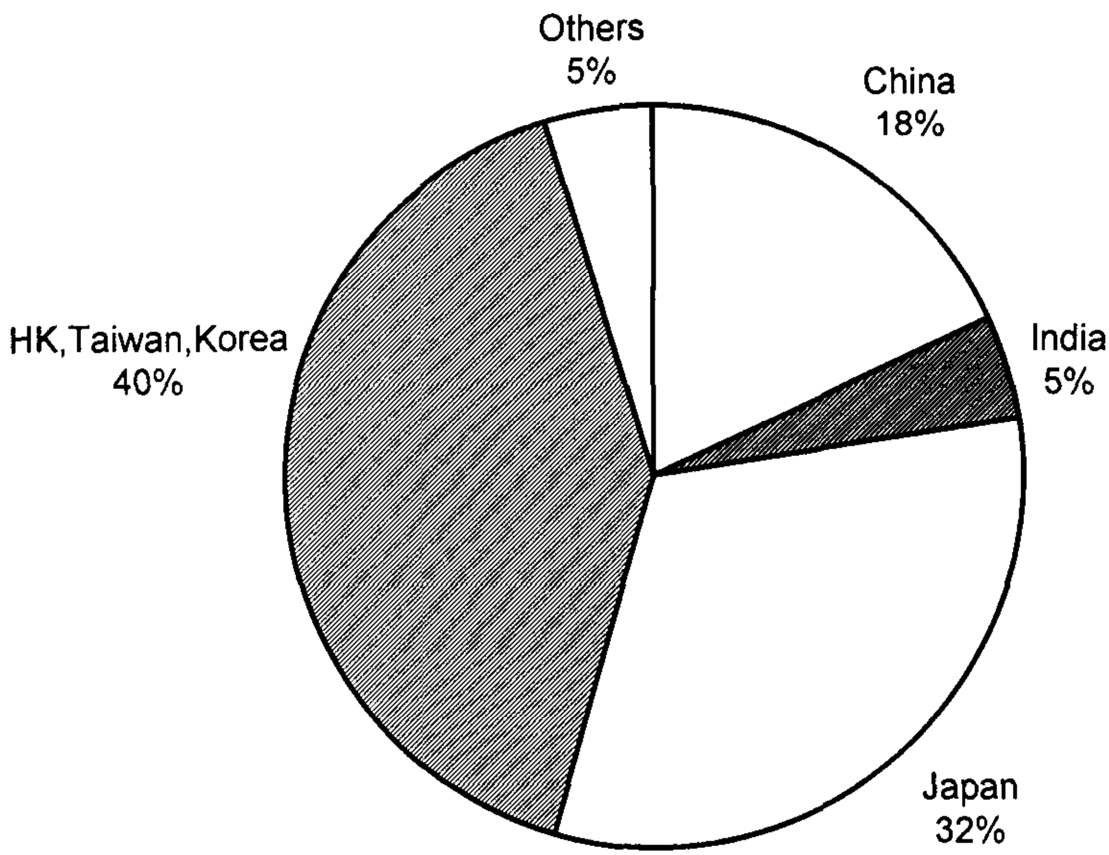



Coal-fired Electricity Capacity in Asia in 1990

(172 GW)

Source: EWC Coal Project, 1992.

Figure 4

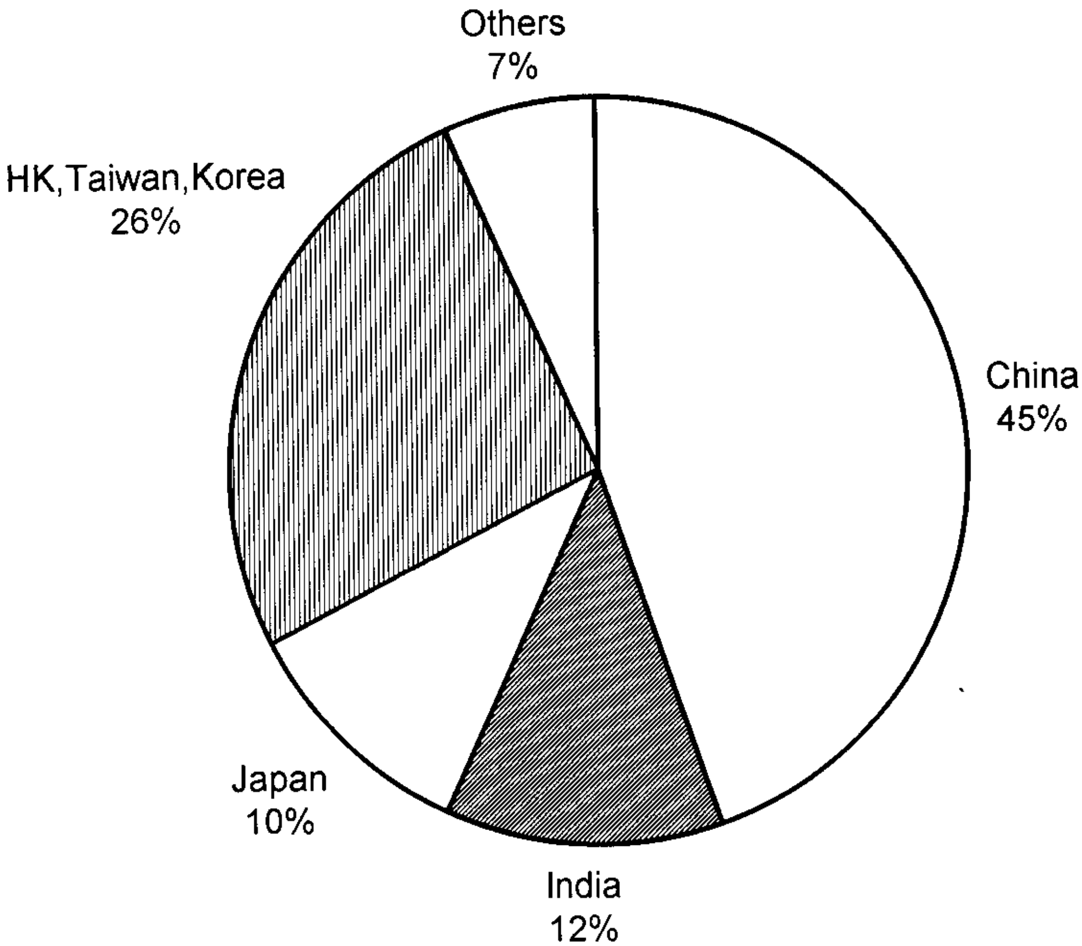



Projected New CCT Capacity in Asia, 1990-2000.

(45 GW)

Source: EWC Coal Project, 1992.

Figure 5

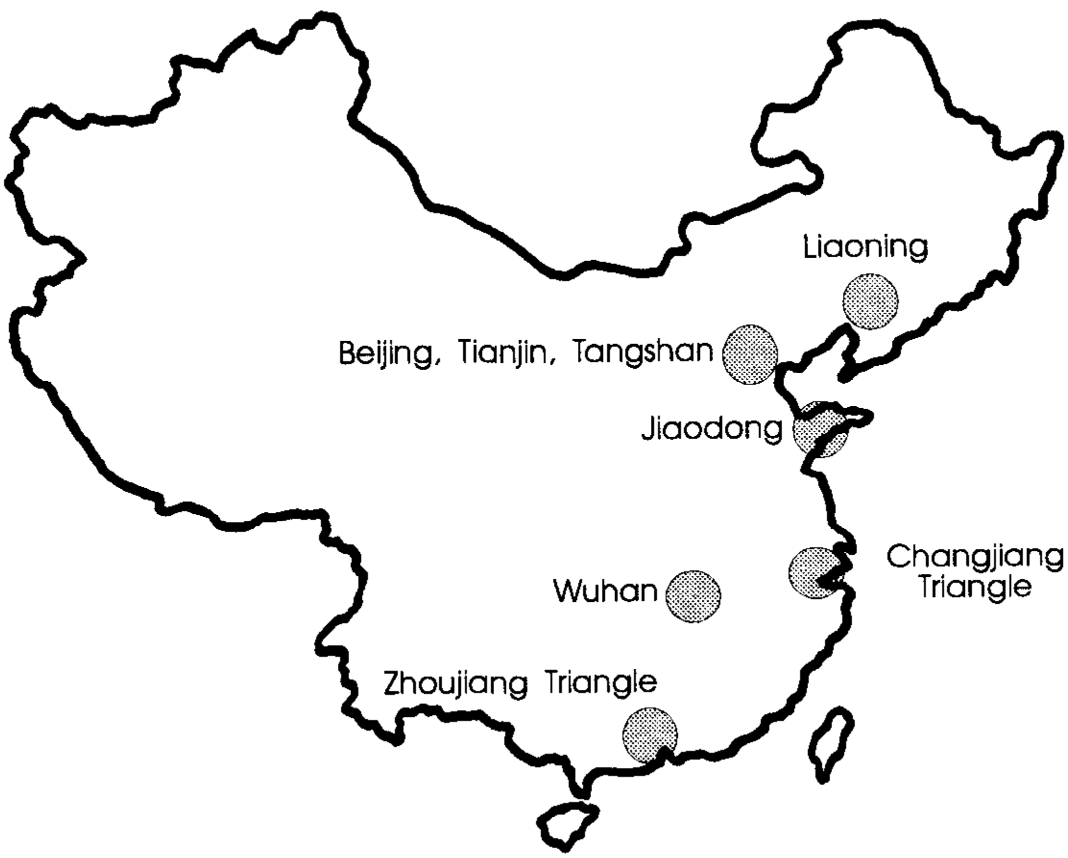



Projected New CCT Capacity in Asia, 2000-2010.

(105 GW)

Source: EWC Coal Project, 1992.

Figure 6




Six load centers consume about 40 percent of total electricity in China.

Figure 7

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Kato, N., Ogawa, Y., Koike, T., Sakamoto, T., and Sakamoto, T., 1991, *Analysis of the structure of Energy Consumption and the Dynamics of Emissions of Atmospheric Species Related to Global Environmental Change (SOx, NOx, and $CO_2$) in Asia*, Report No. 21, National Institute of Science and Technology Policy (NISTEP), Science and Technology Agency, Japan.

University of Pennsylvania, United Nations, and University of Toronto, April, 1992, *Project Link World Outlook*.

# UTILITY PANEL DISCUSSIONS

The Utility Panel will discuss: Experiences panel members have with CCTs, including future prospects for CCTs; Conditions that must exist for utilities to use CCTs (i.e., financial, regulatory, etc.); and How CCTs fit into Utility Clean Air Act compliance strategies (why they were planned and how they are presently perceived).

Moderator:

**Dr. George T. Preston**, Vice President, Generation and Storage Division, Electric Power Research Institute (EPRI)

*Dr. Preston joined the Electric Power Research Institute (EPRI) in 1978 as Program Manager, Desulfurization Processes, moving to Director, Environmental Control Systems in 1981 and Director, Fossil Power Plants in 1984. In January 1991 he became Vice President, Generation and Storage Division. Dr. Preston was instrumental in establishing EPRI's first subsidiary, CQ, Inc., and is Chairman of its Board of Directors.*

Panel Members:

**Dr. James J. Markowsky**, Senior Vice President and Chief Engineer, American Electric Power Service Corporation

**Stephen C. Jenkins**, Senior Vice President, Commercial Development, Destec Energy, Inc.

**Randall E. Rush**, Director, Clean Air Act Compliance, Southern Company Services, Inc.

**George P. Green**, Manager, Electric Supply Resources, Public Service Company of Colorado

**Howard C. Couch**, Manager, Environmental and Special Projects Department, Ohio Edison Company

DEPARTMENT OF ENERGY
CLEAN COAL TECHNOLOGY CONFERENCE
CLEVELAND, OHIO - SEPTEMBER 22-24, 1992

JAMES J. MARKOWSKY, Ph.D.

## INTRODUCTION

American Electric Power generates approximately 85% of its electricity using coal and consumes more than 40 million tons of coal per year. The unique position of AEP as a large consumer of coal in the U.S. and the location of the AEP system on extensive reserves of high sulfur coal, has driven our effort to develop combustion technologies capable of utilizing high sulfur coal efficiently, economically, and in environmentally acceptable ways. We believe that, through the development of clean coal technologies, coal can maintain its pre-eminent position as the fuel of choice for base-load power generation.

The U.S. Department of Energy (DOE), through its Clean Coal Technology initiative, has been the catalyst for bringing industry and government resources to bear on the development of such technologies. A number of these are now in the demonstration phase and on the verge of commercial development. The availability of these varied technologies will provide the basis for continued use of our most abundant fuel reserves, while providing the flexibility to apply the best suited technology to specific situations.

AEP has been a leader in the development of one of these CCTs -- pressurized fluidized bed combustion (PFBC). Our commitment, which began in 1976 with research into PFBC, participation in pilot programs between 1979-1984, moved forward with construction of the 70 MWe Tidd PFBC Project in 1988, and is extending into the future with a program to scale-up PFBC to a 340 MWe plant for commercial operation around 2002.

## TIDD PFBC DEMONSTRATION

The PFBC technology, which exhibited early potential for burning high sulfur coal in a cost effective manner, is being demonstrated today at Ohio Power Company's Tidd PFBC unit. The project, which is the first pressurized fluidized bed combustor in the United States to operate in combined-cycle mode, achieved initial coal fire operation in November, 1990.

Start-up of the unit generally proceeded as expected considering the demonstration status of the technology. Difficulties were encountered throughout the start-up and during the first year of operation. Numerous revisions were incorporated to improve reliability. Availability of the unit has been improving continually. The initial, sporadic operation, which totalled approximately 820 hours on coal in the first year and a sustained run of 110 hours, has been improved to the point where the unit operated continuously at a capacity factor of nearly 70% for approximately 31 days (740 hours) during June/July, 1992. During this run, the unit demonstrated the ability to fulfill its environmental and performance guarantees. While refinements to the PFBC systems are ongoing, the Tidd unit is demonstrating the basic viability of PFBC.

The Tidd Plant has now completed 2,600 hours of coal firing operation.

The next step in AEP's PFBC Technology Program is incorporation of a demonstration-scale hot gas clean up (HGCU) system into the Tidd Project. The HGCU program, which is separately funded by the U.S. DOE as an R&D Project, is scheduled for operation in November 1992. The project will divert one-seventh of the Tidd PFBC combustion gases to a new ceramic-barrier filter and then back to the clean gas outlet header. Operation and testing of the slipstream will last 15-18 months and is intended to demonstrate the viability of HGCU technology to support PFBC, advanced-cycle PFBC, as well as other clean coal technologies such as IGCC.

The final step in AEP's program is the engineering, design and construction of a commercial size PFBC plant. Originally planned as a 330 MWe re-powering of two 150 MWe units at our Sporn Plant, the project has evolved into a 340 MWe Greenfield installation adjacent to our Mountaineer Plant in West Virginia. An extension of the schedule has provided the opportunity to undertake a four-year program of "value engineering" aimed at optimizing PFBC technology and reducing the cost of the first-of-a-kind project to a level consistent with third-of-a-kind. The opportunity to undertake this program will help make PFBC a viable alternative to conventional coal-fired units.

## OUTLOOK FOR AEP'S PFBC PROGRAM

Over the last 1-1/2 decades, American Electric Power has continued to review emerging clean coal technologies. While we continue to consider PFBC an attractive option for base-load generation on the AEP System, we recognize that other CCTs also hold promise to utilize high sulfur coal in an economic and environmentally acceptable manner.

Increasing stringent BACT requirements and the projected performance of competing technologies have caused us to reassess the goals of our PFBC program, particularly with regards to sulfur removal. A 90 percent sulfur removal at a Ca/S molar ratio less than 1.8 looked attractive when

AEP's program was conceived. It is now apparent that 95 percent sulfur removal at a Ca/S molar ratio of less than 1.6 will be necessary to be competitive at the turn of the century.

The goals of the Tidd Test Program have been expanded to address these issues. In addition to completing process and equipment evaluation and feedstock testing, the remainder of the three-year demonstration program will also focus on improving sulfur capture and reducing the Ca/S molar ratio.

## CHALLENGES FACING THE GENERATION OF ELECTRICITY

As utilities look ahead to the challenges of using coal-fired generation, we must ask ourselves this question -- Do our existing coal-based technologies options offer the efficiencies, economics, and environmental performance that will be needed in the future?

Typically, the plants that utilities are putting on line today are ones planned years ago or newly planned Combustion Turbines. The remaining capacity additions are being provided by either NUGs or QFs. The technologies being used are conventional and, typically, gas fired. This is no surprise due to the low cost of both gas- and gas-based generating capacity along with the shorter lead time.

Driving much of this NUGs and QFs activity is the promotion by state regulatory commissions for third party providers of electricity and least-cost planning. The current low price for natural gas, surplus supplies, low first-time cost, and environmental concerns are sustaining this movement for gas-fired capacity for both NUGs and QFs. The forecasted return to historic price premium later in this decade, along with potential supply disruption has done little to mitigate the political and regulatory pressure to pursue gas-based generation.

Another major concern for the future use of coal is the expanded hazardous air pollution program. EPA will be regulating 189 "air toxics", some of which are found in coal in trace amounts. Initially, utility sources are exempt from regulations, with EPA required to conduct a study of emissions of these sources from power plants. If that study indicates a need to control such emissions, EPA must then regulate utility sources. Other than mercury, organic and HCl, most toxic emissions reside in fine particulate.

To further reduce fine particulate emission would require "enhanced" electrostatic precipitators or bag filters. Currently, there is no effective economic way to reduce mercury emission. With respect to reducing Mercury emissions, FGD potentially reduces emissions by 20-30%, fuel switch and/or coal cleaning reduces emissions by 5-10%. Even switching to natural gas would only reduce Mercury emissions by 15-40%. If air toxic reductions are required, their cost would dwarf the cost of meeting Title IV requirements of the CAA.

The last, and perhaps most significant, environmental concern focuses on a worldwide issue--global climate change. The possibility that the earth's climate may be altered through the emission of "greenhouse gases" is receiving an increasing amount of attention. Most of this attention is focussed on the emissions of $CO_2$ from the combustion of fossil fuels. This has led to a growing emphasis on end-use efficiencies as a possible approach to reducing $CO_2$ emissions. However, it will also be important to focus on improving overall efficiency of energy supply. This suggests a clear need to improve existing technologies and the development of new ones.

Innovative clean coal technologies offer possible solutions to this part of the dilemma. By striking the balance between technical, economic, and environmental concerns involved in burning coal, ICCTs may assure us of a continued clean and reliable source of electricity.

Potentially, there currently exists a unique opportunity to commercialize CCTs. The reduction in electric load growth has resulted in a situation where many electric utilities have ample base-load generating capacity to meet system demands into the late 1990s. This window provides the opportunity to demonstrate new technologies and to insure their availability for deployment in the next decade. After the turn of the century, the industry will be facing the need to replace old, worn out coal-fired plants and also meet new load growth requirements.

The need for new base-load generation will develop. The one question is, will CCT -- like IGCC and PFBC -- be allowed to evolve to the level of maturity which is required to be economically competitive. The typical learning curve for new technologies may require replication of 3 to 5 installations of a particular technology before it reaches full maturity and yields full economic benefit. Can this evolution occur in our current regulatory environment?

US DOE, through its Clean Coal Technology initiative, has provided the mechanism to initiate the commercialization process. The final step, however, in the commercialization process will require our nation to look at the long-term benefits of maintaining the coal option and commercializing CCT as one of our long-range strategic objectives. This will require cooperation between industry, government, and regulators to both encourage and help promote the commercialization of CCT.

The problems are:

1. Regulated utilities are typically risk adverse.

2. Conventional gas-fired and coal-fired technologies are typically lower cost when compared to first- and second-of-a-kind clean coal technology.

3. NUGs are poised to provide new generating capacity which is based on mature conventional generating technology -- natural-gas or pulverized coal-fired generation.

4. So, how can utilities be encouraged to pursue commercialization of clean coal technologies like IGCC and PFBC? -- Post DOE funding.

   - Legislation at the state level would need to be passed which would allow state utility regulatory commissions to encourage development of CCT. This may be in the form of:

     - Excluding the first one or two CCT plants from Avoided Cost determination.

     - Agreement that prudently-incurred cost for such CCT plants would be included in rate base.

     - Accounting change such as accelerated depreciation.

   These types of incentives should assist utilities in overcoming the higher risk to specify CCT for future base-load generation.

The system compliance strategy is designed to assure compliance with all emissions limits at minimum system costs and maximum decision flexibility. Its development and frequent updating of the plan requires a carefully coordinated effort between system planning, research and environmental affairs, engineering, finance, fuel, plant operations, and other functions within the service and operating companies.

With respect to Clean Coal Technologies, The Southern Company compliance strategy makes extensive use of low-$NO_x$ burners. Using the cost and performance results from The Southern Company Clean Coal Technology demonstrations and results from demonstrations of other technologies, a model was developed to determine first, the unit-by-unit technology needs for compliance and second, optimum combinations of units and technology to minimize costs. The model baseline is tied to 1991 and 1992 emissions data from the Phase 1 units. This model is updated as more current cost and performance data are made available.

A companion to the technology strategy is the compliance schedule, which merges the possible outage windows for The Southern Company's 28 Phase 1 units with the time available until the compliance deadline. When the schedule has dictated the need to initiate procurement of compliance hardware, the strategy has provided guidance in selecting from the many technological options.

The Southern Company continues to follow, develop, and demonstrate other clean coal technologies for potential application in later phases of the Clean Air Act. Late this year, a second generation Compact Hybrid Particulate Collector (COHPAC) will begin pilot-scale operation at Plant Miller. This technology retrofits a baghouse in place of the last fields of an electrostatic precipitator with the promise of fine particulate collection at a significantly reduced cost over a full baghouse retrofit. Demonstrations are also proposed for selective non-catalytic $NO_x$ reduction, advanced low $NO_x$ digital controls, and simultaneous particulate and $NO_x$ removal on ceramic filters.

**Future Clean Coal Research and Planned Demonstrations**
**The Southern Company**

- Selective Non-Catalytic Reduction (SNCR)
- COHPAC
- Next Generation Low-$NO_x$ Burners
- Air Toxics Measurement and Control
- Advanced Low-$NO_x$ Digital Control
- Ceramic Filters
- Power Systems Development Facility
    - Gasification
    - Pressurized Fluidized Bed Combustion (PFBC)
    - Combustion Turbines
    - Fuel Cells
    - Hot Gas Cleanup

From these past and planned demonstrations of clean coal technologies, The Southern Company will continue its compliance with the provisions of the Clean Air Act. This will be accomplished through the effective use of demonstrated state-of-the-art technologies that provide for environmentally acceptable disposal of combustion and flue gas treatment byproducts while minimizing the impact on ratepayers, stockholders, and the economic development of the southeast.

**Keys to Effective Use of Clean Coal Technology**
**The Southern Company**

Timely/Successful Demonstrations

Cost-Effective Application Opportunities

Consistency with Overall Strategy

Comments from George P. Green not available for publication.

Comments from Harold C. Couch not available for publication.

# SESSION 1:
# Advanced Power Generation Systems

*Chairs: Larry K. Carpenter, DOE METC*
*Dr. Larry M. Joseph, DOE Headquarters*

**American Electric Power Pressurized Fluidized Bed Combustion Technology Update**, Mario Marrocco, Group Manager, PFBC, American Electric Power Service Corporation. Co-author: D. R. Hafer, American Electric Power Service Corporation.

**Nucla CFB Demonstration CCT Program Summary: Project Origins through Test Completion,** Stuart A. Bush, Senior Engineer, Project Coordinator, Tri-State Generation and Transmission Association, Inc. Co-authors: M.A. Friedman, Senior Associate, Combustion Systems, Inc., N. F. Rekos, U.S. DOE Morgantown Energy Technology Center, and T. J. Heller, Tri-State Generation and Transmission Association, Inc.

**Status of the Piñon Pine IGCC Project**, John W. Motter, Advanced Generation Projects Manager, Sierra Pacific Power Company

**DMEC-1 Pressurized Circulating Fluidized Bed Demonstration Project**, Gary E. Kruempel, Manager, Generation Engineering, Midwest Power.
Co-authors: S.J. Ambrose, Midwest Power, and S.J. Proval, Pyropower Corporation

**The Wabash River Coal Gasification Repowering Project**, David G. Sundstrom, Business Development Manager—Coal Gasification, Destec Energy, Inc.

**Status of Tampa Electric Company IGCC Project**, Stephen D. Jenkins, Manager, Advanced Technology, TECO Power Services

# AMERICAN ELECTRIC POWER PRESSURIZED FLUIDIZED BED COMBUSTION TECHNOLOGY UPDATE

M. Marrocco and D. R. Hafer
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Columbus, Ohio 43215

**ABSTRACT**

The American Electric Power Pressurized Fluidized Bed Combustion (PFBC) Program is composed of a number of interlocking pieces. The 70 MWe Tidd PFBC Demonstration Plant is a Round 1 Clean Coal Technology Project that was constructed to demonstrate that PFBC combined cycle technology is cost effective, reliable, and environmentally acceptable. The installation of a hot gas clean up slipstream at Tidd, separately funded by the U.S. DOE as an R&D project, is intended to demonstrate that Advanced Particle Filters (APF) can operate reliably in the PFBC gas stream. The experience gained from these programs will be factored in AEP's 340 MWe commercial PFBC unit, a Round 2 Clean Coal Technology Project that is scheduled for operation around 2002.

*This paper reviews PFBC technology and discusses project goals and milestones* achieved in each of the three areas being pursued. Special emphasis is placed on the start-up and operation of the Tidd PFBC Demonstration Plant.

## INTRODUCTION

The electric utility industry has had a history of innovation in coal burning technology. The American Electric Power Company has been addressing the challenges of coal combustion for over 70 years. Over those decades, significant development efforts were focused on improving the Rankine efficiency of power plants; however, little progress was achieved in improving the fundamental principles of generating electricity. That began to change in the late 1980's. An entirely new menu of options began to emerge. These new clean coal technologies held the promise of maintaining coal's preeminent position as the fuel of choice for power generation.

American Electric Power began investigating pressurized fluidized bed combustion in 1976. The technology exhibited the potential for a power generating option well suited for the AEP system. Over a decade of studies, pilot plant, and component testing was the prelude for the Tidd PFBC Demonstration Unit ground breaking in April, 1988.

## TECHNOLOGY DESCRIPTION

A fluidized bed consists of a mass of granular particles which is maintained in a highly turbulent suspended state by an upward air flow. This fluidized state permits excellent surface contact between the air and the solid particles which permits almost isothermal conditions and efficient combustion. The temperature in the bed is established between the combustion temperature and ash fusion temperature of the fuel--for the Tidd Plant, the temperature is between 1520-1580°F. During combustion, the $SO_2$ generated is removed by the addition of a sorbent, such as dolomite or limestone, to the bed. This process has been demonstrated to remove 90-95% of the sulfur from high sulfur coals. In addition to $SO_2$ removal, the process mitigates the formation of $NO_x$ due to its relatively low combustion temperatures. The high operating pressure of a PFBC unit provides exhaust gases with sufficient energy to drive a gas turbine, allowing a combined cycle configuration, which is more efficient than other alternatives.

## TIDD PFBC DEMONSTRATION

The Tidd PFBC Demonstration Plant, a 70 MWe electric generating station in Brilliant, Ohio, is the first pressurized fluidized bed combustor to operate in combined cycle mode in the United States. Funding for the $193 million project is being provided by Ohio Power Company, the U.S. Department of Energy ($60.2 million), and the Ohio Coal Development Office ($10 million).

The Tidd PFBC Demonstration Plant involves repowering a 1940's vintage coal-fired power plant with PFBC components in order to demonstrate that combined cycle PFBC can efficiently burn high sulfur coal, while meeting environmental requirements for $NO_x$ and $SO_2$ emissions. Additional objectives for the program are aimed at assessing boiler tube erosion in a bubbling bed environment, and establishing the adequacy of a ruggedized gas turbine to perform in a flue gas stream.

The original Tidd Plant, consisting of two 110 MWe conventional coal-fired units, was decommissioned in 1976. The units were preserved in anticipation of a PFBC repowering. Major balance of plant equipment was subsequently utilized in the Tidd demonstration. Major plant additions included the combustor building, economizer, electrostatic precipitator, and coal and sorbent storage areas.

The PFBC power island, which has been incorporated into the existing steam cycle, provides a nominal steam flow of 440,000 pounds per hour at 1300 psia and 925°F, and has a gross electrical output of 70 MWe. Figure 1 depicts the Tidd cycle.

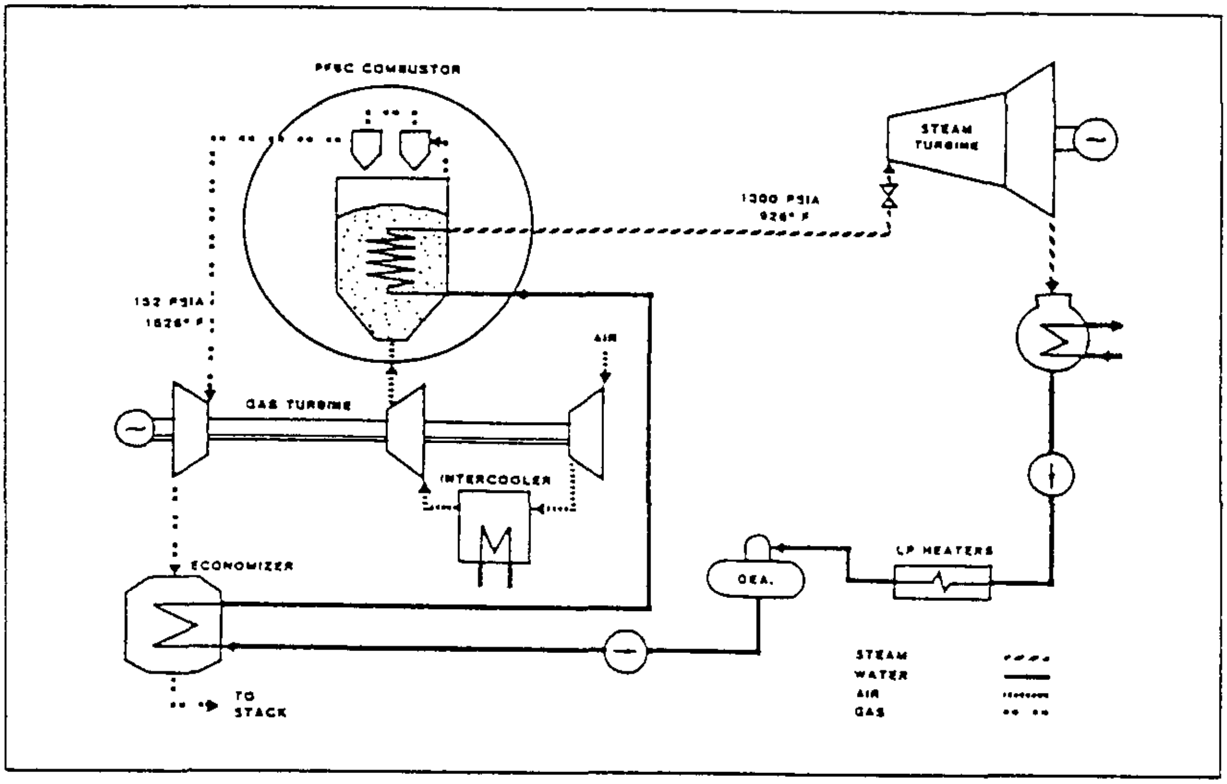


Figure 1 - Tidd PFBC Demonstration Plant Cycle

Combustion air at about 175 psia is provided by the gas turbine compressor to the combustor pressure vessel through the outer annulus of a coaxial pipe. The combustion air fluidizes and entrains bed materials consisting of fuel (coal/water paste), coal ash, and sorbent (either dolomite or limestone).

Seven strings of two-stage cyclones, located within the combustor vessel, remove about 98 percent of the entrained ash from the fluidized bed exhaust gases. The clean, hot gases leave the pressure vessel via the inner cavity of the coaxial pipe and are expanded through an ASEA Stal GT-35P gas turbine, then exit through the turbine exhaust gas economizer. An electrostatic precipitator cleans the gas of particulate prior to exhausting to the atmosphere.

The steam cycle is a typical Rankine cycle with a once-through boiler. Condensate is heated in three stages of low pressure heaters and the gas turbine intercooler as it is pumped to the deaerator. A single high pressure heater and an economizer raise the final feedwater temperature to about 480°F. The feedwater passes through the boiler bottom zone and into the in-bed evaporator surface. Steam generated there is conveyed to a vertical separator outside the pressure vessel; flow to the separator is two-phase up to about 40 percent load and slightly superheated at full load. Saturated or slightly superheated steam from the vertical separator is routed back to the in-bed tube bundle where it passes through primary and secondary superheater sections. Final steam temperature is controlled by spray attemperation between the primary and secondary superheaters.

Coal is injected into the combustor as a coal water paste nominally containing 25 percent water by weight. Paste preparation begins by reducing the 3/4" x 0 feedstock to -1/4" in a double roll crusher. The crushed coal is conveyed to a vibratory screen (which controls the coal top size), and then into the coal water paste mixer where water is added. The mixer discharges the coal water paste to two interconnected surge tanks which feed six hydraulically driven piston pumps, each of which supply an individual in-bed fuel nozzle.

Sorbent feedstock sized at 3/4" x 0 is reduced to 1/8" x 0 by a hammer mill crusher. A vibratory recycle screen controls the top size of the prepared sorbent. Crushed sorbent is injected into the fluidized bed via two pneumatic feed lines supplied from dual lock hopper strings.

Bed ash, which comprises about 50 percent of the total ash produced, is removed from below the bed via a lockhopper system. Elutriated ash collected by the cyclones is removed via a pressurized pneumatic transport system which depressurizes and cools the ash without using valves or lockhoppers.

## HOT GAS CLEAN UP SYSTEM

An additional feature incorporated into Tidd during 1992 is a demonstration scale hot gas clean up (HGCU) system, separately funded by the U.S. DOE as an R&D project. One-seventh of the PFBC main gas flow will be diverted to a new ceramic barrier filter and backup cyclone, and will then be directed back to the secondary cyclone outlet header inside the combustor pressure vessel. Operating and testing of the HGCU slipstream will occur during the last 15 to 18 months of the Tidd three-year test period, and is intended to demonstrate the viability of HGCU technology to support PFBC, advanced-cycle PFBC, and other clean coal technologies. Figure 2 illustrates the incorporation of HGCU at Tidd.

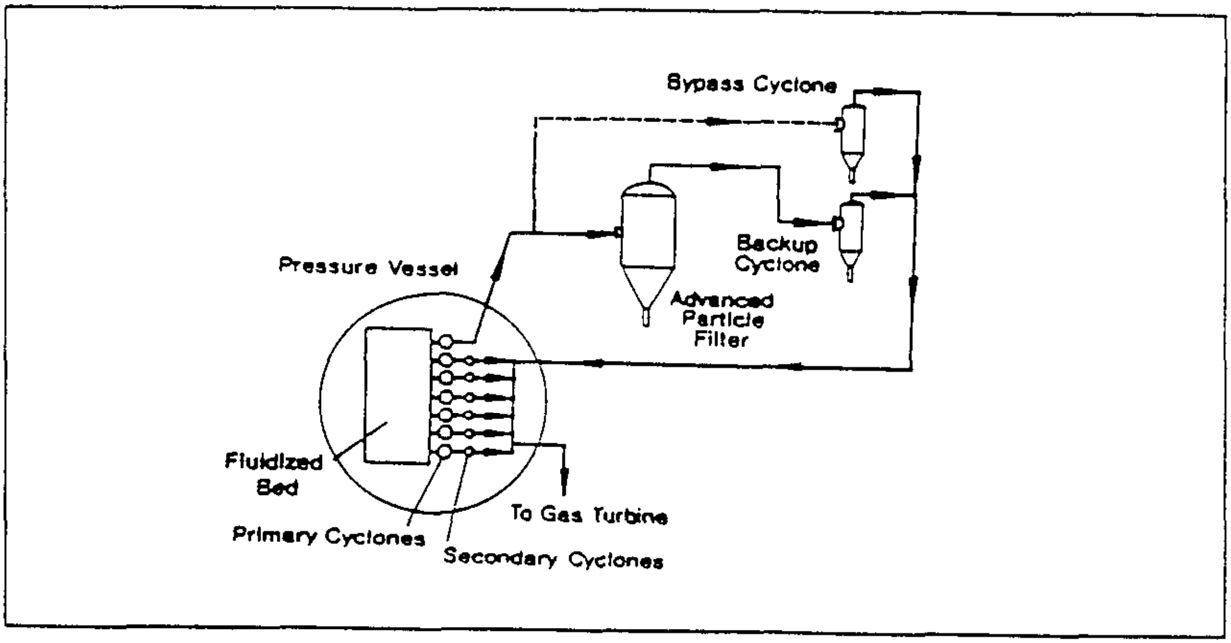


Figure 2 - Tidd HGCU Test Facility Arrangement

## OPERATIONAL SUMMARY

The Tidd PFBC Plant achieved its first coal fire in November, 1990. Operation in the first year was sporadic, with the longest sustained run being 110 hours and the total operation on coal 818 hours.

In mid-September, 1991, the unit was taken out of service for a 12-week outage aimed at addressing the operational issues which had been identified. Significant modifications were made to address both operational and equipment difficulties. Table 2 provides a listing of the areas of modification.

The unit was returned to service in December, 1991. Unit operation was more consistent, but still limited by operating problems. From December 15 to March 5, 1992, the unit operated on coal for a total of 530 hours, with the longest sustained run lasting 154 hours. In mid-March, 1992, cracks were discovered in the blade roots of the single-stage, low pressure gas turbine. (The problem was determined to be fatigue cracking due to resonant vibration, and as such is a gas turbine design issue, not a PFBC technology concern.) As a result, a nine-week outage was taken to replace the turbine blades. The HGCU test system, configured in the bypass mode, was also tied in at this time. Additionally, an extensive coal preparation test program was undertaken during this outage in an attempt to improve coal paste quality and crusher reliability. The unit was restarted on May 10, 1992, but an expansion joint failure in the newly installed HGCU loop forced a shutdown. The HGCU piping problem required extensive rework, so it was decided to isolate the one cyclone string used by HGCU and to return the unit to operation with six cyclone strings. Tidd returned to service on June 9, 1992. The unit ran continuously for approximately 740 hours at nearly 70% capacity factor. The unit was removed from service on July 10, 1992, to perform equipment inspection.

## POST-BED COMBUSTION

In a bubbling bed PFBC, burning which occurs above the bed is referred to as post-bed combustion. Two types of post-bed combustion were experienced during the first year of operation. The first type occurred primarily at low bed levels (reduced load) and centered in the cyclone dip leg (the lower portion of gas cleaning cyclones). These fires were attributed to excessive carbon carryover at low bed levels (reduced load). The other type of fires were observed at higher bed level (higher loads) and involved the entire gas stream. These fires were attributed to combustion of volatiles that had not burned in the bed due to localized oxygen depletion near the fuel nozzles.

Both types of post-bed combustion resulted in excessive freeboard and cyclone temperatures which, at times, approached material limits. Load curtailment and unit shutdowns were typical consequences of post-bed combustion.

Both types of fires were the result of incomplete combustion; efforts were directed toward achieving better distribution of fuel in the bed. It was subsequently determined that drier coal water paste reduced the intensity of the fires. This was apparently due to the ability of the fuel feed nozzles to produce better dispersion of the drier coal water paste, thereby reducing localized volatile release and improving combustion.

During the Fall of 1991, modifications were made to the fuel injection system to achieve better fuel distribution. In addition, a freeboard gas mixing system was installed. The purpose of the system was to mix the freeboard gases/solids to prevent localized concentration of volatiles or unburned carbon. This would spread the heat release from these combustibles over the entire gas stream and prevent localized hot spots. In addition to these physical changes, an intensive program was undertaken to reduce coal water paste water content, while maintaining pumpability.

The improved paste quality and fuel distribution, in conjunction with freeboard mixing, has resulted in acceptable in-bed combustion and no evidence of significant post-bed volatile or carbon fires has been noted in recent operation.

## BOILER

The amount of in-bed boiler tube surface provided initially was inadequate and resulted in achieving only 73 percent of design heat transfer at the original full bed height of 126 inches. During the Fall 1991 outage, approximately 25 percent more in-bed surface was added above the existing tube bundle with the intent of achieving full design heat absorption. At the new full bed height of 142 inches, the heat absorption is still only approximately 93 percent of design. Investigations are underway to determine the reason for the remaining shortfall.

## TEG ECONOMIZER

The finned tube turbine exhaust gas economizer has exhibited significantly heavier fouling than anticipated, resulting in excessively high gas side velocity. Vibration induced by the high velocity is believed to have been the cause of four tube failures that occurred in mid-1991. Four soot blowers and some additional anti-vibration tube supports were installed during the Fall 1991 outage. While no additional leaks have been experienced since then, heavy fouling in regions of the economizer that the soot blowers could not reach was still occurring. Four additional soot blowers have been installed.

## SORBENT INJECTION SYSTEM

At initial start-up, the sorbent injection system experienced numerous operating difficulties related to valve and rotary feeder malfunction and wear. Severe erosion of the sorbent transport piping was also a problem. Through various material changes and equipment replacement, the system is now reliable.

An additional concern relates to the formation of sorbent-based "clinker" deposits in the tube bundle above the two sorbent injection nozzles and the adjacent coal nozzles. The clinkers, which are agglomerates of bed material and very fine sorbent particles (with no evidence of fusion), appeared for the first time in January, 1992. The cause of the clinkers was not readily apparent. However, changing the point of sorbent admission into the bed (by shortening the injection nozzles) and slightly increasing the sorbent injection velocity has eliminated clinker formation during subsequent runs. Additional investigations and experiments will be performed in the future in order to obtain a better understanding of this phenomenon.

## COAL PREPARATION/COAL INJECTION SYSTEM

The coal preparation system was designed to crush 3/4" x 0 coal to a size distribution suitable for both good paste pumpability and good combustion within the fluidized bed. The critical parameter for good pumpability is that 20 percent of the crushed coal must be -325 mesh, which then permits the moisture content of the paste to be maintained in a range of 24 to 25 percent by weight. As the -325 mesh fraction declines below 20 percent, the moisture content of the paste must be increased to achieve good pumpability.

During the first 14 months of operation, the coal crusher was capable of producing only 12 to 15 percent -325 mesh fines. With this size consistency of coal, the moisture content of the paste had to be increased to the range of 25 to 28 percent by weight to maintain pumpability. Numerous changes were made to the crusher during this period to improve the production of -325 mesh fines, but without success. Modifications included installation of larger drives, the cutting of grooves on the roller surface, and operation in several different control modes.

Prior to the gas turbine outage in March, 1992, a recycle loop was added to the system to permit up to 100 percent of the feed coal to be recycled through the crusher. This has been effective in producing 18 to 22 percent of -325 mesh fines. The 31-day continuous run in June-July, 1992 verified that this mode of operation produces a consistent coal water paste with 24 to 25 percent moisture by weight.

Another problem experienced with the coal system was rapid corrosion of carbon steel surfaces in contact with paste. The nominally 3.5 percent sulfur Pittsburgh No. 8 coal being tested at Tidd, when mixed with water, produces a paste with a pH as low as 3. This resulted in significant corrosion damage to the coal paste mixer and coal paste pumps from November, 1990 to September, 1991. During the Fall 1991 outage, all carbon steel surfaces in the mixer and paste pumps were replaced with austenitic stainless steel. To date, these modifications have been successful.

**GAS CLEANING CYCLONES/ASH REMOVAL SYSTEMS**

The gas cleaning equipment for Tidd consists of seven parallel strings of cyclones. Each string has two stages of cyclones referred to as the primary and the secondary. Ash collected in each cyclone is pneumatically transported from the combustor vessel using the combustor pressure as the driving force.

During early plant operation, from December, 1990 to March, 1991, pluggage of the secondary cyclone ash removal system resulted in unacceptable unit availability. Numerous modifications were made to reduce pressure drop in this system and thus increase transport capacity. Originally, the seven primary and seven secondary ash lines combined into one line which was routed to the cyclone ash silo. By March, 1991, the primary and secondary systems were decoupled and the secondary ash line was routed to the precipitator inlet. In addition, several modifications were made to the ash lines inside of the combustor vessel to further improve transport capacity.

Starting in March, 1991, the secondary ash transport system was sufficiently reliable to permit continuous operation. At shutdowns, however, ash buildup in the cyclone dip legs would not permit restart of the unit until the ash was removed from the dip leg. In order to minimize the impact of this buildup on unit operation, the dip legs of all secondary cyclones were shortened approximately 20 feet during the Fall 1991 outage.

After the Fall 1991 outage, pluggage of the secondary ash system again adversely impacted unit availability. In mid-January, 1992, pluggage was found to be caused by excessive pressure drop in the secondary ash line outside of the combustor vessel. The pressure drop was reduced by redesign and replacement of the ash line, and the system began to function properly. The secondary ash removal system is now considered marginally acceptable. Some pluggage still occurs at start-up, but experience has shown that these tend to clear themselves when combustor vessel pressure increases after firing coal. During the 31-day run, though, one secondary cyclone remained plugged. Subsequent inspection revealed the pluggage was due to restriction of the ash pickup nozzle by a foreign object.

Operation of the primary ash removal system has generally been acceptable, except for a two-month period in mid-1991, when pluggage of the primary ash removal system began to impact unit operation. At first, each pluggage could be traced to a process upset, usually in the sorbent injection system. It was believed that the process upset resulted in a temporary increase in ash loading to the cyclones which overwhelmed the transport capacity. The system was totally dismantled and inspected as part of the Fall 1991 outage and it was found that air in-leakage into the primary ash lines inside the combustor vessel significantly reduced the transport capacity of the system. The process upsets were merely overwhelming a system that was operating at marginal capacity.

An extensive program was instituted during the Fall 1991 outage to eliminate the air in-leakage in both the primary and secondary ash removal systems. Bolted connections were replaced with welded connections where possible, shop fabrication flaws in cast components were repaired, and extensive quality control measures were applied to tightening procedures for the bolted connections that could not be replaced.

**GAS TURBINE**

The gas turbine has experienced relatively small, but measurable amounts of erosion after 2100 hours of coal-fired operation. Periodic inspections have shown that normal unit operation produces very little erosion; however, the erosion rate increases significantly when cyclone ash removal lines are plugged. The most serious erosion has occurred when a primary cyclone ash removal line plugs. In such an event, the corresponding secondary ash removal line is overwhelmed and quickly plugs.

Primary cyclones normally collect 98 percent of the ash in the gas stream and the secondary cyclones remove approximately 33 percent of the remainder. When an entire string plugs, the gas turbine dust loading increases tenfold. A more important factor, however, is the size of the particles reaching the gas turbine. Each cyclone stage collects progressively smaller particles, with the normal secondary cyclone exhaust dust containing virtually no particles larger than five microns. When an entire string is plugged, the gas turbine is exposed to particles as large as 250 microns. The erosion rate is much more sensitive to particle size than to dust loading. Generally, when only a secondary cyclone ash removal line plugs, the increase in erosion rate is minimal. During the 31-day run, the unit was operated with one secondary cyclone plugged and erosion was higher than anticipated. The system configuration of six cyclone strings instead of seven is thought to have contributed to this increased erosion.

An ongoing problem with the gas turbine has been bypassing of air from the high pressure compressor directly into the turbine. The present estimate of this leakage is approximately three times the design value for seal and cooling air flow. Given the limits on compressor volumetric flow, this leakage results in limiting the unit firing rate, with the limit being more severe with increasing ambient temperature. Modifications to a suspected area of leakage during the Fall 1991 outage did not resolve the problem, and investigations are continuing to identify the source of the leakage.

As noted earlier, fatigue cracks attributed to resonant vibration were found in the root area of a number of low pressure turbine blades in March, 1992. New blades designed to prevent this condition were installed before the unit was returned to service in May, 1992.

**UNIT PERFORMANCE**

Unit performance tests for contract acceptance were conducted in June, 1992. The tests were run at full bed height with the maximum firing rate and highest bed temperature attainable at that time. Firing rate was limited by the available air and the in-bed tube bundle absorption capability. The steam flow was impacted by deficiencies in both in-bed tube bundle and economizer absorption capabilities. In addition to the effects of reduced firing rate and low steam flow, gross unit output was affected by degraded steam cycle efficiency. Preliminary results for key parameters, along with a comparison to expected values, are provided in Table 3. Also noted in the table is data from a test run in February, 1992, in which approximately full load heat input was attained. The higher firing rate was possible due to increased gas turbine compressor capacity with a cooler ambient temperature and operation at a lower excess air level.

Table 1

TIDD PFBC PERFORMANCE

COMPARISON OF TEST RESULTS TO EXPECTED RESULTS

| | Test June, 1992 | Test Feb., 1992 | Expected |
|---|---|---|---|
| Unit Firing Rate ($MW_T$) | 190.3 | 205.1 | 206.3 |
| Gross Unit Output ($MW_E$) | 60.2 | 70.0 | 70.0 |
| Gas Turbine Output ($MW_E$) | 13.2 | 15.8 | 15.0 |
| Mean Bed Temperature ($^oF$) | 1550 | 1579 | 1540 |
| Main Steam Flow (klb/hr) | 395 | 432 | 442 |
| Economizer Gas Outlet Temp ($^oF$) | 419 | 428 | 355 |
| Air Flow to Combustor (klb/hr) | 593 | 593 | 655 |
| Combustion Efficiency (%) | 99.4 | N/A | 98.0 |
| Excess Air (%) | 20.1 | 13.3 | 25.0 |
| Sulfur Retention | 92.6 | 93.1 | 90.0 |
| Ca/S Molar Ratio (as tested) | 2.05 | 2.17 | – |
| Ca/S Predicted at 90% Retention | 1.82 | 1.87 | 2.00 |
| $NO_x$ Emissions (lb/$10^6$ Btu) | 0.18 | 0.15 | 0.50 |

## SUMMARY

The Tidd PFBC Demonstration Plant has completed over 2100 hours of coal-fired operation and has met its environmental performance objectives. With the 100-hour run at full load and the 31-day continuous run, the unit has met its reliability objectives. Also, with the exception of the deficiency in gas turbine power output as a result of excessive air leakage, the PFBC power island equipment has met all performance guarantees.

The main operating problems prior to this year's successful runs can be attributed to the coal preparation and cyclone ash removal systems. Our experience to date emphasizes the importance of proper coal preparation to achieve reliable coal injection and proper coal combustion within the bed. Of similar importance is performance of the cyclone ash removal system to ensure that the exhaust gas is sufficiently clean for gas turbine survivability.

While refinement of all PFBC systems is likely, the cyclone ash removal and coal preparation systems will require the most significant efforts for commercialization of PFBC technology.

## OUTLOOK FOR AEP'S PFBC PROGRAM

Over the last decade, AEP has continued to review emerging clean coal technologies, and we have continued to reassess our support for the PFBC option. While we continue to consider PFBC an attractive option for base load coal generation, we recognize that tightening of government environmental standards and the projected performance of competing technologies mandate a reassessment of our PFBC program goals, particularly with regards to sulfur removal. Although 90 percent sulfur removal at a Ca/S molar of 2.0 looked attractive when AEP's PFBC program was conceived, it is now apparent that 95 percent removal at Ca/S molar ratios of less than 1.6 will be necessary.

Therefore, in addition to completing process evaluation and feedstock testing, as scheduled, during the remainder of the three-year demonstration period, the Tidd test program has been expanded to focus on achieving a more stringent sulfur capture.

## PFBC UTILITY DEMONSTRATION PROJECT

The Philip Sporn Plant PFBC Project was conceived as a 330 MWe repowering of the existing Sporn Plant Units 3 and 4, with start-up in 1996. The project was proposed to the U.S. Department of Energy in 1988 and was accepted for funding as part of the CCT II initiative. A cooperative agreement was signed in April, 1990 for the $660 million program. DOE agreed to cost share $185 million dollars in project costs. Ohio Power Company and Appalachian Power Company, both operating subsidiaries of American Electric Power Company, were to fund the balance.

Subsequent re-evaluation of AEP's PFBC commercialization program indicated that economic considerations favored a "Greenfield site" over a repowering. It was also determined that a scheduled extension was appropriate based on system load growth considerations. The 330 MWe Sporn Repowering Program evolved into the 340 MWe PFBC-001 "Greenfield" Plant, with a start-up around 2002. Extensive site studies indicated that AEP's Mountaineer site, in New Haven, West Virginia, on the Ohio River about 55 miles northwest of Charleston, West Virginia, was the most advantageous location.

The extended schedule for the commercial plant provides the opportunity to mitigate the risks of a commercial scale-up. AEP is taking advantage of this additional time by undertaking a four-year "value engineering" program. The first two years of which will concentrate on optimization of PFBC technology. The second two years will focus on integration of the PFBC power island with the balance of plant.

The stated goals of the "value engineering" program is to mitigate technical risk by drawing on the operating experience of the three PFBC units presently operating (Tidd, Vartan, Escatron) and by testing innovative concepts for PFBC commercial application (i.e. increased sulfur capture at lower Ca/S molar ratios). An additional goal of the program is to lower the projected cost of the "first-of-a-kind" PFBC unit to a level typically associated with "third-of-a-kind" units.

AEP recently entered into a contract with the Babcock & Wilcox Company, the licensee of ASEA Brown Boveri Carbon, for systems and process optimization studies aimed at addressing these goals (see Table 4).

Plans are underway for a concerted testing effort at Tidd aimed at achieving $SO_2$ capture of 95% at Ca/S molar ratios of less than 1.6.

The scheduled revision of the PFBC-001 commercial project should not significantly impact the commercializing program for PFBC. The significant reduction in electric load growth has resulted in a situation where many utilities in the nation find themselves with an ample generating capacity. It is not likely that a significant number of base loaded, coal fired units will be committed in the remainder of this decade. The need for base load generation will surface early in the next decade. Successful demonstration of PFBC technology at Tidd, optimization of both technology and economics, as a result of AEP's "value engineering" program, and design, construction and operation of a commercial PFBC-001 unit around 2002 should provide utility executives with the basis for deployment of PFBC technology on a time scale consistent with the need for base load power.

# Nucla CFB Demonstration CCT Program Summary: Project Origins through Test Completion

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## Abstract

The Nucla circulating fluidized bed (CFB) boiler is a 110 MWe dual combustor, non-reheat design that was constructed between 1985 and 1987 to repower an existing 36 MWe station located in western Colorado. At the time, the boiler was the largest CFB in the world and the first utility application of this technology in the United States. As part of its demonstration of utility-sized fluidized bed combustion technology, the Electric Power Research Institute (EPRI) selected the project in 1985 as a host for a detailed test program. In 1988, the U.S. Department of Energy (DOE) became a co-sponsor of the test program as part of its demonstration of Clean Coal Technology. The repowered Nucla plant was owned and operated by the Colorado-Ute Electric Association, Inc. (CUEA) through April 1992. At this time, Tri-State Generation and Transmission Association, Inc. assumed ownership and control of the station in a bankruptcy reorganization.

The unit burns a low sulfur (0.5 %) bituminous coal mined in western Colorado that is delivered to the plant by truck. Periodically, the station has taken advantage of the fuel flexibility offered by the technology by switching to least cost coal supplies. This has included blends of bituminous gob and gilsonite. Crushed limestone is used within the combustion process to control $SO_2$ emissions to 0.3 lb/MMBtu and 70 percent retention. As a result of lower mean combustor operating temperatures compared to other coal-burning technologies, NOx emissions are inherently low and meet regulated levels of 0.4 lb/MMBtu without add-on processes for control.

As part of the Demonstration Test Program, a total of 72 steady-state performance tests were conducted on the unit. In addition, specialized tests were performed to quantify transient characterisitics of the boiler, along with the performance of the air heater, baghouse, and hot cyclones. Monthly operating statistics and costs were also tabulated during the test period. This data and information have been documented in a series of reports published by EPRI and the DOE. This paper summarizes the history of the project along with some of the key results from the test program.

## Introduction

The original Nucla Station was built in 1959 and consisted of three identical stoker-fired units, each rated at 12.5 MWe. Due to its reduced position on the dispatch order resulting from poor station efficiency and increased maintenance costs, the decision was made in 1984 to upgrade and repower the station with a new 419,580 kg/h (925 klb/h) circulating fluidized bed boiler and 74 MWe turbine-generator. This followed a detailed review of existing technologies, including several bubbling and circulating fluidized bed designs.

At that time, there were several small bubbling FBC's operating in the United States, but it wasn't until 1985 that the first two industrial CFB's built by Ahlstrom Pyropower came into commercial operation. The boiler contract for Nucla was eventually awarded to Pypropower for their proposed CFB design. Utilizing twin combustion chambers, each chamber represented a 2:1 scale-up in height and plan area over their largest operating unit.

Except for the old stoker-fired boilers, most of the equipment from the old plant, including the turbine-generator sets, was refurbished and reused bringing the gross plant electrical output to 110 MWe. The project offered several advantages including a station heat rate improvement of 15%, reduced fuel costs due to the inherent fuel flexibility of the CFB design, lower emissions required by New Source Performance Standards, and life extension 30 years beyond the plant's original design.

Construction of the new CFB boiler began in the spring of 1985 and was completed over a two-year period. First turbine roll was initiated in May 1987 and first coal fires were achieved in June of that year. Acceptance tests on the design western bituminous coal were conducted in October, 1988 and operational tests on a high ash (~35 wt.%) and high sulfur (~2.5 wt.%) western bituminous coals were performed the following year.

Detailed planning for a CFB demonstration test program was initiated by EPRI in 1985. In August 1988, the U.S. Department of Energy added the project to its Clean Coal Technology Program. The test program was implemented in two phases with Phase I covering the period from February 1987 through June 1990. This phase was jointly sponsored by both organizations. Phase II covered the period from July 1990 through January 1991 and was solely sponsored by the U.S. DOE with administration by the Morgantown Energy Technology Center.

A total of 72 steady-state performance tests were completed during the Phase I and II test programs at various unit loads, excess air levels, primary to secondary air ratios, fuel and sorbent feed configurations, calcium/sulfur ratios, and bed temperatures. In addition, specialized instrumentation was used to measure heat transfer to the water walls, to study the extent of gas mixing in the combustion chambers, and to monitor and record the transient behavior of the unit.

Final capital costs associated with the engineering, construction, and start-up of the repowered Nucla Station with CFB technology were approximately $112.3 million. This represents a cost of $1,123/net kW. As part of an Economic Evaluation performed during the Phase II test program, total monthly production expenses were documented and recorded between September 1988 and January 1991. Total power costs associated with operating the plant during this period were $54.75 million resulting in a normalized cost of power production of $63.63/MWh. The average operating cost per month over this time period was $1,887,959. Fixed costs, including interest, taxes, insurance and depreciation, represented 61.54 percent of this total. Fuel expenses and maintenance costs accounted for 26.19 percent and 5.51 percent of this total, respectively.

## Facility Description

### General Arrangement

The new CFB boiler generates 925,000 lb/h of steam at 1510 psig and 1005 °F, utilizing a twin combustion chamber design with a height of approximately 110 feet and a total plan area of 1055 square feet. A plan and side view of the boiler arrangement is shown in Figure 1. Each combustion chamber is nearly square in cross-

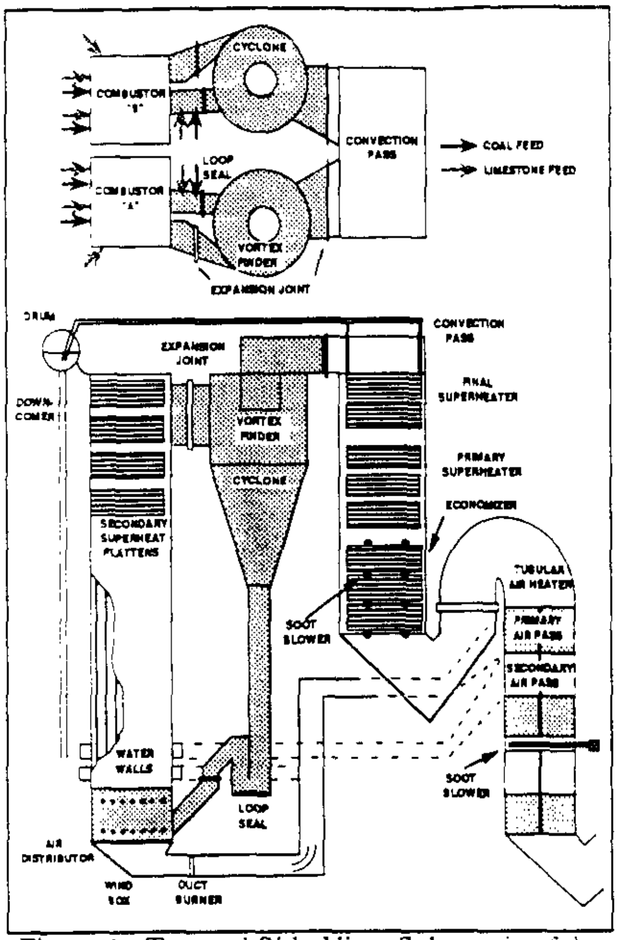


Figure 1. Top and Side View Schematic of the 110 MWe Nucla CFB.

section and consists of water wall, membrane construction with a refractory-lined lower section. Each chamber is equipped with a refractory-lined hot cyclone approximately 23 feet in diameter. The outlets of the cyclones join together and enter a common convection pass. Captured solids are recycled to the lower combustion chambers through loop seals located near the bottom of each chamber. The two combustion chambers have individual systems for fuel, air, and sorbent supply and ash removal. Because both chambers share a common steam/water circuit and steam drum, independent firing is not possible.

Exhaust Gas Flow Path

Flue gas and uncollected fine particles exit the cyclone at combustor operating temperatures and flow through a common convection pass, tubular air heater, shake/deflate type baghouses (three from the original stoker-fired units and a fourth new baghouse), and induced draft fan to the stack. The convection pass is equipped with primary and final superheater tube surfacing and an economizer. Because of emissions control within the combustion process, backend equipment for $SO_2$ and NOx control is not required to meet Colorado emission standards.

Coal and Limestone Feed

Coal is delivered to the plant by truck and is crushed to 1/4 by 0 inch by primary, secondary and final crushers. It is then stored in two in-plant silos with a combined 24-hour full-load firing capacity. After exiting the silos onto one of six gravimetric feeders (three per combustion chamber), coal is gravity fed to two locations along the front wall and to the recycle loop seal return leg along the rear wall of each chamber. A rotary valve, combined with fuel feed combustion air, isolate the hot combustion chamber gases from the gravimetric feeders. Limestone is pneumatically conveyed in the vicinity of the coal feed points along the front and rear walls and to a single location along the side wall of each chamber.

Combustion Air

Combustion air is supplied to the process by primary and secondary air fans. Air from the primary air fan flows through the tubular air heater where it is preheated to approximately 450°F before entering the windboxes and passing through the air distributor. Air from the primary air fan also enters the combustion chambers through ports located approximately two feet above the air distributor, and through the coal feed ports. Secondary air is distributed through ports located approximately eight feet above the air distributor. High pressure blowers also supply fluidizing/combustion air to the side mounted ash coolers and loop seals. Additional air enters the combustion chambers as transport air through the limestone feed ports.

Solids Waste Removal
Bed material, or bottom ash, is removed from the combustors through side-mounted fluid bed ash coolers (two per combustion chamber). Here, the ash is cooled and fines are returned to the lower combustion chamber. Depending on the temperature, coarse solids exiting the ash coolers can be cooled further in a water-cooled screw, or can be vacuum transported directly to a storage silo for truck disposal. Fly ash is collected at three points in the process including the convection pass, air heater and baghouse hoppers. The ash is vacuum conveyed to a storage silo where it is wetted and transported to the disposal site by truck.

Water/Steam Circuitry
The water/steam circuitry for the boiler is shown in Figure 2. High pressure feedwater enters the economizer tube bundle located in the lower convection pass. The outlet tubes from the economizer travel vertically through the top of the convection pass, pass over the top of the cyclones, and enter downward into the drum. The vertical length of economizer tubing serves as a support structure for the primary and final superheater tube bundles. Water from the drum flows by gravity down one of three downcomers to lower water-wall headers. The water-walls of the two combustion chambers rely on natural circulation and account for approximately 55-60 percent of the total heat duty.

Saturated steam exiting the steam drum travels to the steam-cooled convection cage and then into the primary superheater located in the convection pass. From here, it splits into parallel flow paths and through attemporator spray stations before entering the secondary superheaters located in the upper furnace sections of each combustion chamber. The secondary superheaters consist of four panels that wrap around three walls of each combustion chamber. After exiting the combustion chambers, steam travels through a second set of attemporator spray stations and crosses over into the final superheater tube bundles located in the upper

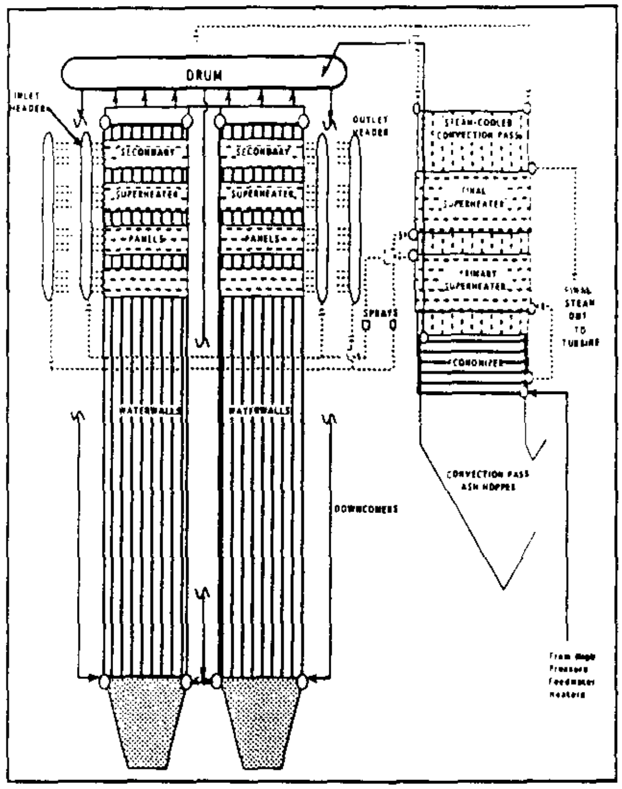


Figure 2. Schematic of Steam/Water Circuitry.

convection pass. The cross-over into the final superheater serves to equalize steam temperatures that may exist due to differences in combustion temperatures and heat transfer rates between the two furnaces.

From the final superheaters, superheated steam at 1500 psig and 1005°F travels to the new 74 MWe turbine-generator. Controlled steam extraction off the new turbine at 640 psig is routed to the three existing 12.5 MWe turbine-generator sets. Each of the old units is equipped with refurbished condensers, hotwells, condensate pumps, and low pressure feedwater heaters. Condensate from the old units then passes to the new deaerator storage tank via forwarding pumps. The arrangement of the turbine-generator sets is shown in Figure 3.

## Summary of Demonstration Test Program

Detailed planning for a test program was initiated by EPRI in 1985. This included the devel-

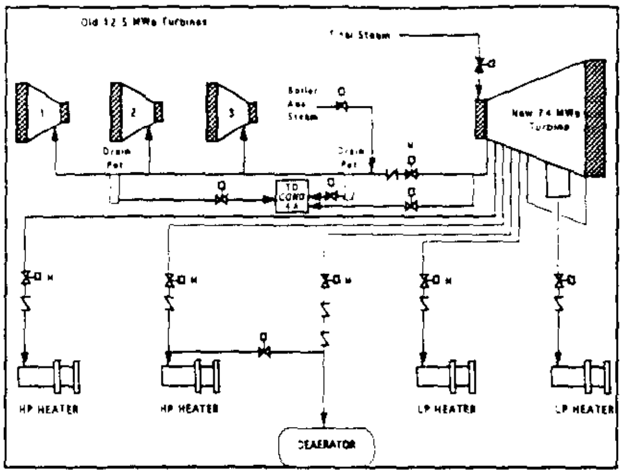


Figure 3. Schematic of Turbine Arrangement.

opment of test plans, resource planning, specifications and installation of additional instrumentation, data acquisition hardware and software, and specialized test equipment. Preparation for the test program commenced in February 1987 with the arrival of a permanent testing staff to the site.

In August 1988, after expressing interest in the Nucla project as part of its Clean Coal Technology Program, the U.S. Department of Energy awarded a Cooperative Agreement No. DE-FC21-89MC25137 to the CUEA as co-sponsors of the test program along with EPRI. This was done after careful review of the overall scope and objectives of the Nucla project to verify the DOE's criteria for demonstrating clean coal technology in new and retrofit/upgrade applications. Administration of the cooperative agreement was performed by the DOE's Morgantown Energy Technology Center located in Morgantown, West Virginia. The objective of the DOE Cooperative Agreement was to conduct a cost-shared Clean Coal Technology Project to demonstrate the feasibility of circulating fluidized bed combustion technology and to evaluate economic, environmental, and operational benefits of CFB steam generators on a utility scale.

To address the operational and environmental benefits of the technology, a total of 72 steady-state performance tests were completed during the test program. Of these tests, 8 were conducted on a local Nucla coal and 2 on a local Dorchester coal as part of alternate fuels testing, and 62 were completed on Salt Creek coal. This latter coal was the baseline fuel used for the test program. A summary of the properties of these fuels is shown in Table 1. A total of 22 tests were performed at 50% maximum continuous rating (MCR), 6 tests at 75% MCR, 2 tests at 90% MCR, and 42 tests at full load (110 MWe). Except for limestone sizing tests, which were not possible with existing plant preparation equipment, all independent process variables proposed in the original test matrix were completed.

| Property | Nucla Mine | Salt Creek | Dorchester | GOB | Gilsonite |
|---|---|---|---|---|---|
| Heating Value | | | | | |
| • kJ/kg | 17,400 to | 24,312 | 21,010 | 19,685 | 34,573 |
| | 27,520 | | | | |
| • Btu/lb | 7,490 to | 10,460 | 9,040 | 8,470 | 14,875 |
| | 11,840 | | | | |
| Sulfur, % | 0.52-2.75 | 0.44 | 1.53 | 0.46 | 0.4 |
| Ash, % | 9.8-42.8 | 14.6 | 22.8 | 26.0 | 13.76 |
| Moisture, % | 4.1-14.9 | 10.0 | 10.97 | 12.3 | 0.36 |
| Fixed Carbon, % | 43.5 | 43.4 | 35.8 | na | 16.5 |
| Volatiles, % | 28.4 | 32.3 | 30.4 | na | 69.38 |

Table 1. Properties of Fuels Burned.

Test results and information collected to satisfy the project's objectives have been documented in a series of test reports issued by CUEA as part of the DOE Cooperative Agreement. These reports include a Final Report summarizing results over the duration of the test program, three Annual Technical Reports covering the period from unit start-up through 1988, 1989, and 1990 through test completion, a Detailed Public Design Report, an Economic Evaluation Report, a Performance Test Summary Report containing the data summaries from each of the 72 steady-state performance tests, and one Quarterly Technical Progress Report for the period from October 1990 through January 1991.

## Project Milestones

A summary of the major milestones and events from the inception of the project through test completion is shown in Table 2. During the period from 1988 through 1991, the unit operated with an average availabiltiy of 60.1%, equivalent availability of 56.5%, capacity factor of 40.6%, and net plant heat rate of 12,055 Btu/NkWh. Maximum monthly availability and capacity factors were 97.9% and 85.6%, respectively. The lowest monthly on-line net plant heat rate was 11,102 Btu/NkWh.

| | | |
|---|---|---|
| 1982 | | Study Initiated for Upgrading and Extending the Life of the Nucla Station. |
| 1983 | | EPRI Funds Two Design Studies for Different CFB Boilers. |
| 1984 | | Loan Approved by the National Rural Utilities Cooperative Finance Corporation. |
| 1984 | Summer | Selection of Pyropower for Boiler Contract. |
| 1985 | Spring | Start of Construction. |
| 1987 | Feb | EPRI Test Team Mobilizes to Site. |
| | March | Completed Boil Out. |
| | April | Steam Blows. |
| | May | First Steam to Turbine. |
| | June | First Coal Fires. |
| | Sept. | Overheat Incident and Outage. |
| | Dec. | Completed Repairs and Resumed Start-Up. |
| 1988 | March | Achieved Full Load. |
| | July | First Acceptance Test with Design Fuel. |
| | August | Cooperative Agreement Awarded by DOE. |
| | Oct. | Completed Acceptance Testing on Design Fuel. |
| 1989 | Jan. | Completed Refractory Repairs. |
| | March | Completed Instrument Calibration and Uncertainty Analysis. |
| | April | Completed First Performance Test as Part of the Test Program. |
| | Sept. | Outage to Upgrade Primary Air Fan. |
| | Oct. | Completed High Ash and High Sulfur Coal Operational Acceptance Tests. |
| 1990 | June | Completed Phase I of Test Program. |
| 1991 | Jan. | Completed Phase II of Test Program. |
| | Sept. | Start of Four Month Maintenance Outage. |
| 1992 | March | Completed Test Program Reporting |
| | April | Ownership Transfer of Nucla Station to Tri-State Generation and Transmission Association, Inc. |
| | June | Initiation of Plant Upgrades. |

Table 2. Summary of Project Events and Milestones.

## The Test Plan

The overall test plan was based on the integration of several sub-test plans, each with its own objectives, procedures, and test matrix. These sub-test plans include: 1) initial instrument calibration, 2) establishing uncertainty analysis parameters, 3) collection of plant operating statistics, 4) detailed boiler performance testing, 5) unit start-up and restart characteristics, 6) load following response, 7) gas mixing characteristics, 8) furnace heat transfer, 9) hot cyclone performance, 10) operational performance of solids feed and disposal sytems, 11) tubular air heater effectiveness, 12) baghouse performance, 13) materials monitoring, 14) overall environmental performance, 15) economic assessment, and 16) alternate fuels testing.

As part of satisfying the objectives in these areas, a total of 72 steady-state performance tests were completed on the local Nucla, Salt Creek, and Dorchester coals. For each test, uncertainty analysis was applied to the performance calculations to establish a statistical confidence interval on the final results. Uncertainty analysis was also used to optimize instrument calibration and solids sampling frequencies. Acceptable uncertainties in calculated results, such as boiler and combustion efficiencies, were achieved with 5 coal, 2 limestone, 2 bottom ash and 6 fly ash samples for each test. Process data, such as temperature and pressure measurements, are collected at high enough frequencies with modern data acquisition systems that these measurements are not restrictions on uncertainty reduction in the final results. For this unit design with this coal variability, process stability, instrument quality, and calibration frequency, the above solids sampling scenario represents an optimum whereby further increases in quantity lead to diminsihing returns in uncertainty reductions for calculated output variables.

In order to complete the above solids sampling scenario, performance tests were conducted over a seven hour period prior to changes in independent operating parameters. Based on transient test data, the boiler was typically held at steady-state conditions for a minimum of 24 hours prior to testing. This duration was often longer if large changes in load or boiler chemistry occurred prior to a test.

Special instrumentation was installed on the boiler to measure heat transfer to the combustor water walls, and gas mixing within one of the two combustion chambers. In parallel with normal plant operation, a high speed data acquisition system was used to monitor routine start-ups, restarts, shutdowns, and load ramping response.

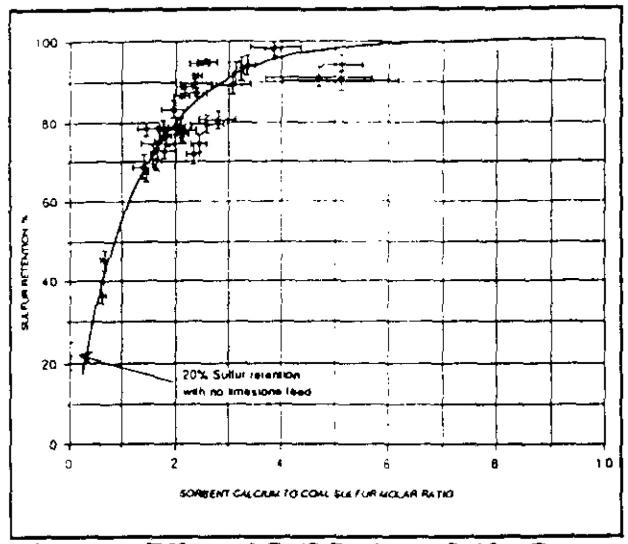


Figure 4. Effect of Ca/S Ratio on Sulfur Retention: Bed Temp. < 880°C or 1620°F (Ref.2).

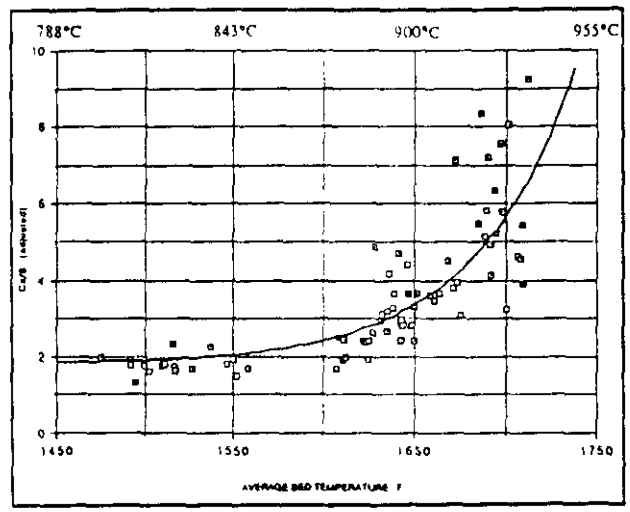


Figure 5. Effect of Temperature on Calcium Requirements (Reference 2).

## Summary of Test Results

### Emissions Performance

The Nucla CFB has demonstrated the ability to meet New Source Performance Standards for $SO_2$, NOx and particulate emissions across the load range. For $SO_2$ emissions control, a higher limestone feed rate (Ca/S ratio) was required for combustor operating temperatures above 880°C (1620°F) to maintain a given sulfur retention. Figure 4 shows sulfur retention as a function of the Ca/S ratio for average bed temperatures less than 880°C (1620°F). Ca/S ratios are based on the calcium in the sorbent only and does not account for any calcium in the coal. Data in the figure are for the local Nucla and Salt Creek coals only. The calculated uncertainty band widths are shown along with the data points. In this figure, Ca/S ratios of 1.5 and approximately 4.0 are required to achieve 70 and 95 percent sulfur retentions, respectively.

Above 880°C (1620°F) operating temperatures, Ca/S ratios increase in order to maintain a given sulfur retention. Figure 5 shows the effect of the average bed temperature on the Ca/S ratio required for 70 to 75 percent sulfur retention. For an operating temperature of approximately 925°C (1700 °F), a Ca/S ratio of approximately 5.5 is required.

There is no discernable difference in sulfur capture performance between the local Nucla and Salt Creek coals. The Dorchester coal, with a higher average sulfur content of 1.5 weight percent compared to 0.7 and 0.5 percent for the local Nucla and Salt Creek coals, had lower Ca/S ratio requirements for a given retention. For tests conducted at 90 percent sulfur retention, the local Nucla and Salt Creek coals averaged a Ca/S ratio of 3.2, while the higher sulfur Dorchester coal averaged a ratio of 2.2.

Fuel and sorbent feed distribution tests indicated that balanced coal feed rates between the front and rear walls of each combustion chamber yields the best sulfur capture performance. Coal flow to only one of the walls results in higher limestone requirements. Limestone feed configuration tests were restricted due to mechanical limitations of the feed equipment. However, data indicate that limestone feed in close proximity to coal feed results in the optimum sulfur capture performance.

Excess air affected Ca/S requirements to the extent that increases in this parameter reduced operating temperatures, particularly above 915°C (1680°F). Below this temperature, adjustments to excess air between 10 and 20 percent did not appear to influence Ca/S ratio requirements. No effect on sulfur capture performance could be seen from changes in the primary to secondary air ratio from 2 to 1. Primary air is defined here as the air flow through the distributor plate. All other air flow is categorized as secondary air.

NOx emissions were less than 145 mg/nJ (0.34 lb/MMBtu) for all tests completed in the Phase I and II programs. The average amount for all tests was 77.5 mg/nJ (0.18 lb/MMBtu), which is well below the state regulated limit of 215 mg/nJ (0.5 lb/MMBtu). As with $SO_2$, the most influential factor affecting NOx emissions was the combustor operating temperature, as shown in Figure 6 for the local Nucla and Salt Creek coals. Some of the scatter in these data is attributed to the limestone feed rate. By tagging data points in Figure 6 with the Ca/N ratio for the test, where Ca is the calcium in the limestone and N is the nitrogen in the fuel, it was found that points with Ca/N ratios between 3.7 and 4.5 fell consistently above the correlation. Points with ratios between 0 and 1.0 fell below the correlation. This effect was also observed in real-time as NOx emissions fluctuated with changes in the limestone feed rate at a given load.

NOx emission trends were similar for the local Nucla, Salt Creek, and Dorchester coals except for slight shifts in absolute amounts as related to the limestone feed rate. Correlations between absolute NOx emissions and excess air, limestone feed configuration, primary to secondary air ratio, and CO concentrations were not apparent. NOx emissions were slightly higher for tests conducted with coal feed to the front walls of the combustor only.

CO emissions also correlated well with bed temperature, as shown in Figure 7 for each of the three coals discussed above. Emissions increased with decreasing temperatures from as low as 70 ppmv at 925°C (1700°F) to 140 ppmv at 790 °C (1450°F). Some of the data scatter is due to different coal and sorbent feed configurations, excess air ratios, and coal types, although

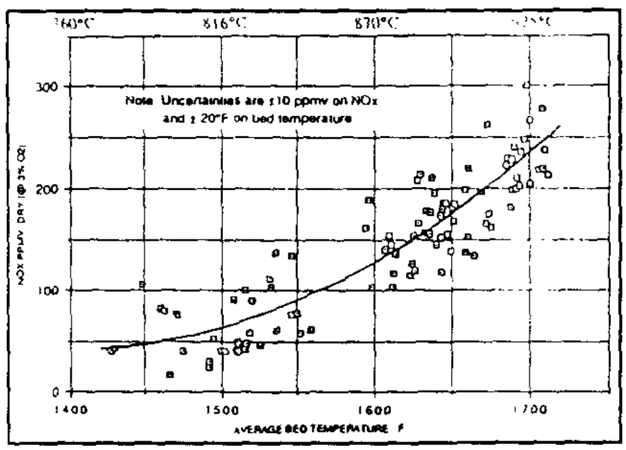


Figure 6. Effect of Temperature on NOx Emissions (Reference 2).

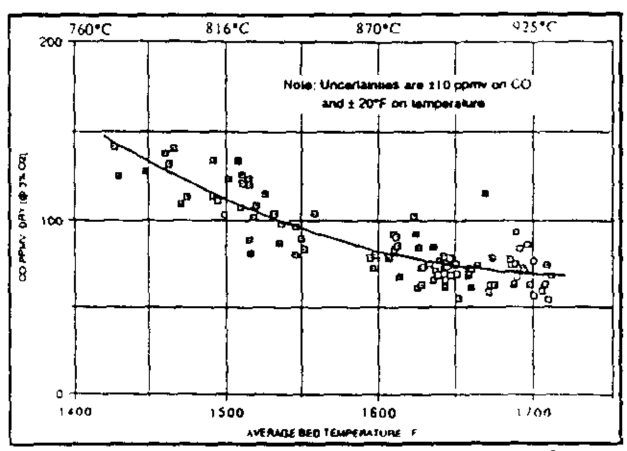


Figure 7. Effect of Temperature on CO Emissions (Reference 2).

no direct correlations between CO emissions and these parameters were apparent.

Particulate emissions were a major concern during the design stage of the Nucla plant because of the size and shape of CFB fly ash. However, using a shake/deflate design with teflon-coated, fiberglass bags and an air-to-cloth ratio of 0.1 $m^3/s/m^2$ (2.0 $acfm/ft^2$), collection effficiencies of 99.96 percent were obtained. The average emission rate during compliance tests was 3.1 mg/nJ (0.0072 lb/MMBtu), which is below the NSPS value of 12.9 mg/nJ (0.03 lb/MMBtu). Full load flange-to-flange pressure drop averaged between 0.013 - 0.017 $kg/m^2$ (5.0 - 6.5 in.wg.).

The important influence of combustor operating temperature on $SO_2$, NOx, and CO emissions is apparent from the above data. At Nucla, operating temperatures varied with unit load from approximately 790°C (1450°F) at half-load to as high as 925°C (1700°F) at full-load. Adjustments to primary-to-secondary air ratio and ash cooler classifying velocities did not produce significant changes in operating temperatures at a given load. Temperatures were found to vary with solids loading in the freeboard region of the boiler which, for the most part, was uncontrollable and varied with the ash content of the input coal stream. From an emissions standpoint, relatively constant operating temperatures should be maintained across the load range to maximize performance and minimize operating costs, i.e., limestone consumption and ash disposal. However, with the low sulfur coals tested, the costs associated with the higher limestone feed rates were not appreciable.

Combustion and Boiler Efficiency

For all performance tests, combustion efficiency ranged between 96.9 to 98.9 percent. No significant difference between Salt Creek, the local Nucla, and Dorchester coals was apparent and no single process parameter (e.g., boiler load, bed temperature, excess air, primary to secondary air ratio, coal feed configuration, etc.) appeared to have a direct impact on the results. Carbon in the fly ash and bottom ash accounted for an average of 93 and 5 percent, respectively, of the unburned carbon leaving the boiler. The remaining 2 percent exits the boiler in the flue gas as carbon monoxide.

Boiler efficiencies varied between 85.6 to 88.6 percent for Phase I and II tests. Table 3 summarizes the major contributions to boiler heat loss from the Salt Creek coal tests. Dry flue gas sensible heat and burning hydrogen are the largest contributors to the total heat loss. The former can be reduced by decreasing the excess air of the combustion process. The local Nucla coal resulted in the highest efficiencies due to the lowest losses from moisture in the fuel. Dorchester coal produced the lowest efficiencies due to a higher moisture content in the fuel and a larger sorbent calcination loss. The latter is the result of a higher sulfur content in the Dorchester coal. The net plant heat rate improved with boiler load increasing from 13,070 kJ/NkWh (12,400 Btu/NkWh) at 50% MCR to 12,225 kJ/NkWh (11,600 Btu/NkWh) at full-load.

| DESCRIPTION | AVG | MIN | MAX | RANGE |
|---|---|---|---|---|
| • Unburned Carbon | 1.9 | 1.1 | 3.1 | 2.0 |
| • Sensible Heat in Dry Flue Gas | 4.7 | 4.0 | 5.4 | 1.4 |
| • Fuel and Sorbent Moisture | 1.0 | 0.7 | 1.1 | 0.3 |
| • Latent Heat in Burning H2 | 3.4 | 3.2 | 3.6 | 0.4 |
| • Sorbent Calcination | 0.3 | 0.0 | 0.6 | 0.6 |
| • Radiation and Convection | 0.6 | 0.4 | 0.8 | 0.4 |
| • Bottom Ash Cooling Water | 0.6 | 0.4 | 1.2 | 0.8 |
| • Miscellaneous | 0.2 | 0.1 | 0.3 | 0.1 |
| • TOTALS | 12.6 | 11.4 | 13.5 | 2.1 |

Table 3. Summary of "Losses" Terms for Boiler Efficiency (Reference 2).

Transient Characteristics

Steam conditions, unit load, and coal and gas flow rates were presented for a cold start-up in Reference 1 and are shown in Figures 8, 9, and 10. In this example, the time required from initial light-off to turbine roll was 7 hours.

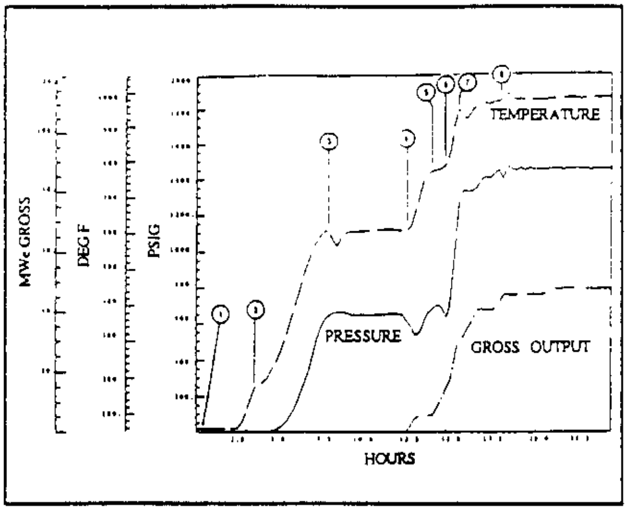


Figure 8. Steam Conditions and Unit Load During a Cold Start-Up (Reference 2).

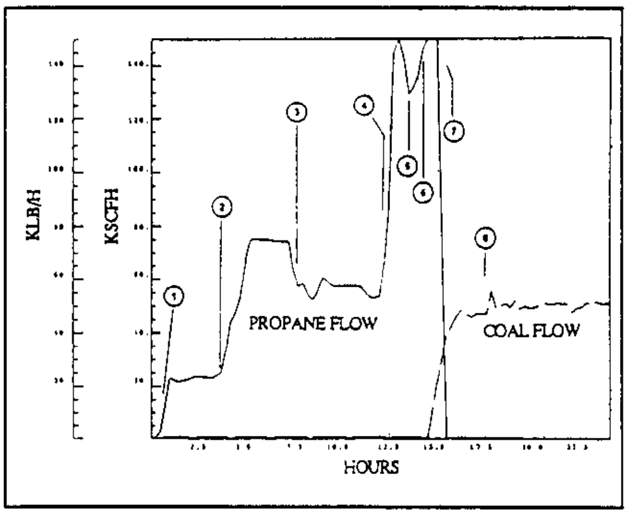


Figure 9. Coal and Gas Flow During a Cold Start-Up (Reference 2).

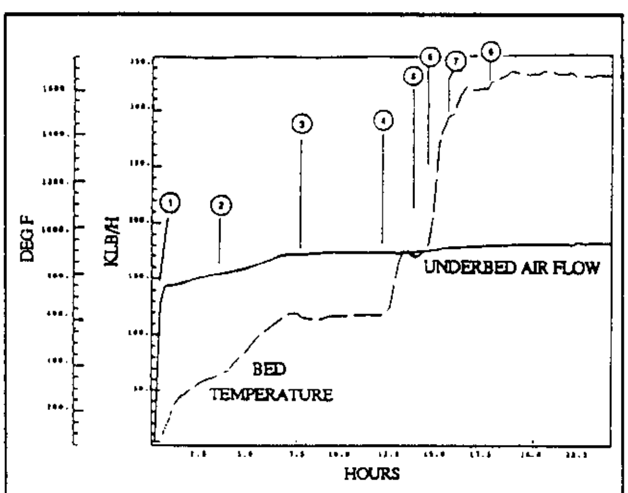


Figure 10. Underbed Air Flow and Bed Temperatures During a Cold Start-Up (Ref. 2).

turbine roll (heat soak) was approximately 5 hours, synchronization and load stabilization at 5 gross MWe was 2 hours, and the time required to reach 45 gross MWe was 3 hours. The numbered sequence on these figures is as follows:

1. Start fans and duct start-up burners (following 5 minute purge).
2. Start in-bed start-up burners (two of three per combustor).
3. Turbine roll once 55°C (100°F) superheat temperatures are reached.
4. Synchronize generator and raise load to 5 MWe on gas. Start third start-up burner in each combustor.
5. Increase gas firing rate to raise bed temperatures to 510°C (950°F) required for initiation of coal feed. Load increases to 20-25 MWe.
6. Initiate coal flow and increase load.
7. Shut-off start-up burners once bed temperatures have reached 760°C (1400°F).
8. Increase load to 45 MWe on the new 74 MWe turbine and begin bringing the three old 12.5 MWe turbines on-line.

Under optimum conditions, the unit can achieve full-load from a cold condition in 10 to 12 hours. The first five hours are required to achieve 55°C (100°F) superheat temperatures at approximately 4.16 MPa (600 psig) prior to turbine roll. Drum metal temperature limitations of 55°C/h (100°F/h) are a restriction during the first two hours of gas firing, but decrease to less than 42°C/h (75°F/h) for the remainder of the start-up. Refractory temperature increases generally do no exceed 33°C/h (60°F/h), which is well under the 55°C/h limitation suggested by the manufacturer. Between 2 and 5 hours from initial start-up, the gas firing rate is established to minimize drum level fluctuations and to stay conservatively within drum and refractory ramp limitations. This is followed by a 3 hour turbine soak interval, a 1 hour period at minimum load on gas at 5 MWe to stabilize, and finally, the initiation of coal flow and increase in unit output.

Except for the time required to bring each of the three older 12.5 MWe turbines on-line, the remainder of time to full-load is dictated by the boiler/turbine ramp rate. The latter was tested successfully at 5 MWe/min over a $\pm$40 MWe range. Testing at 7 MWe/min identified drum level control as a limitation. It may be possible to improve performance at this rate by adjusting the calculated steam flow rate used in three-element drum level control.

Warm restarts (off-line for less than 12 hours) generally require 2 to 4 hours to achieve a stable operating load of 45 MWe. This interval is dictated by the time required to reestablish superheat temperatures and/or minimum bed temperatures of 510°C (950°F) necessary for the initiation of coal feed. The time to reestablish superheat temperatures is determined by how quickly the turbines are brought off-line following a controlled shutdown or unit trip. The time to reestablish minimum bed temperatures is controlled by the time required to remove fans from service during a shutdown or unit trip, and the time required to restart fans and complete a unit purge during a restart. Hot restarts (unit off-line for less than four hours) typically follow the same scenario although, in some cases, the turbine can remain on-line and gas and/or coal feed can be reestablished immediately.

During controlled tests, the Nucla CFB achieved a maximum gross load of 117 MWe and a minimum load of 30 MWe for a turndown ratio of approximately 4:1. Maximum load was limited by loss of net positive suction (NPSH) to the boiler feed pumps, and minimum load was restricted by low bed temperature limitations of 700°C (1300°F).

## Conclusions

The demonstration test program on the Nucla CFB commenced in 1987 and was completed over a three year period during which time a total of 72 steady-state performance tests were conducted. Data from these tests demonstrate the ability of the unit to reliably and economically meet New Source Performance Standards for emissions control across the load range. Combustor and boiler efficiencies have been found to meet or exceed expectations for a variety of different fuels including blends of low quality bituminous gob. The owners have taken advantage of the boiler's fuel flexibility by periodically switching to least cost fuel supplies. The unit has fit well into the regional electrical power system by meeting cycling demands including cold start-up and hot/warm restart times, load ramping rates, and unit turndown ratios.

As a large scale demonstration of a new technology, the unit encountered various problems which influenced the overall availability of the plant during the first five years of operation. These problems have been documented in the technical reports and journal articles published over the past several years. Under the new ownership, unit availabilities in excess of 80 percent will be required in order to meet contractural requirements. In order to achieve this, Tri-State Generation and Transmission Association, Inc. has embarked on an effort to upgrade several areas of the unit design. These include modifications to the boiler water walls, secondary superheaters, combustor and cyclone refractory installations, and air distributor nozzle design. The experiences at Nucla, along with its successors, will form the basis for these design changes.

Performance testing as part of the Demonstration Program was concluded in January 1991 and all data analysis and reporting were completed in April 1992. The various reports document the unit design, operating history, acceptance test results, equipment performance and reliability, monthly operational statistics, steady-state performance test results, and environmental and economic performance over the course of the test program. This is a valuable resource for utilities, industrial users, and independent power producers planning new capacity and considering CFB technology as an option. The database and information generated and documented by EPRI and the DOE during the course of the Phase I and II test programs is the most comprehensive and available resource of its kind in the CFB technology area.


### Acknowledgements

In order to implement the Test Program, EPRI established an on-site test team which, in addition to a permanent staff, was made up of loan employees from various utilities. Members of this team included the following organizations: Alabama Electric Cooperative, Bechtel Corporation, Colorado-Ute Electric Association, Commonwealth Edison, Consolidated Edison, Duke Power, Electric Power Research Institute, Electricite de France, Northern States Power, Public Service and Gas Company of New Jersey, Philadelphia Electric Company, Pyropower Corporation, Radian Corporation, Salt River Project, Union Electric, and Wisconsin Electric Power Company. In addition, the test program received support from United Engineers (Denver) for the design and installation of test equipment and computer hardware, from Southern Research Institute for baghouse testing, and from Combustion Systems Inc. for report preparation.


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3) *Colorado-Ute Nucla Station Circulating-Fluidized Bed (CFB) Demonstration, vol. 1: Test Program Preparation, and vol. 2, Test Program Results*, Final EPRI Reports No. GS-7483, October 1991.

4) *Final Technical Report for the Period 1987 through 1991*, prepared for the U.S. DOE under Cooperative Agreement No. DE-FC21-89MC25137, October 1991.

5) *Economic Evaluation Report*, prepared for the U.S. DOE under Cooperative Agreement No. DE-FC21-89MC25137, March 1992.

6) *Colorado-Ute's Nucla Circulating AFBC Demonstration Project, vol. 2: Plant Equipment and Systems Design*, Final EPRI Report No. CS-5831, February 1989.

# STATUS OF THE PIÑON PINE IGCC PROJECT

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## ABSTRACT

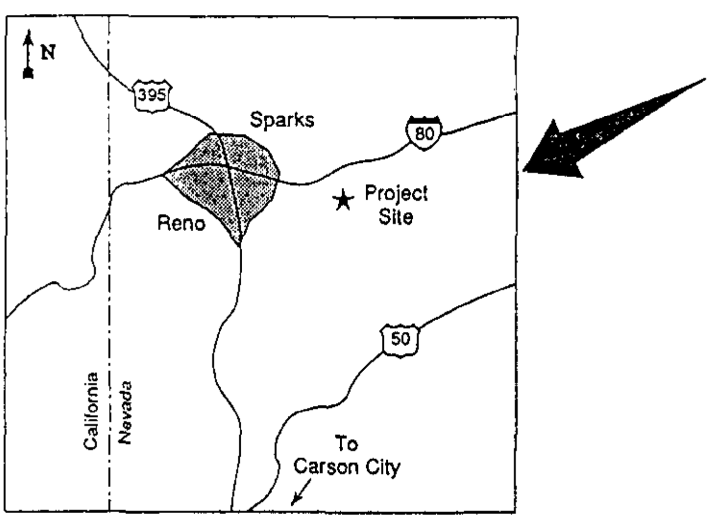
Sierra Pacific Power Company (SPPCo.) plans to build an integrated coal gasification combined cycle (IGCC) power plant, burning 800 tons per day of western coal to produce 80 megawatts of electrical power at a high capacity factor. The project was selected by the U.S. Department of Energy (DOE) for funding under the fourth round of the Clean Coal Technology Program and will be constructed at SPPCo.'s existing Tracy power plant site which is located approximately 20 miles east of Reno, Nevada. The project is named the Piñon Pine Power Project; a DOE-SPPCo. Cooperative Agreement for the project was completed in July, 1992 and will provide for approximately $135 million of funding from the government--50% of the expected total project costs for construction and 42 months of O&M plus fuel.

Foster Wheeler USA (FWUSA), as prime sub-contractor to SPPCo., will provide engineering, procurement, and construction management for the new facility. The M. W. Kellogg Company will design the gasifier island using their air-blown Kellogg-Rust-Westinghouse (KRW) technology incorporating hot gas cleanup under a subcontract with FWUSA. This paper summarizes the project, and describes SPPCo.'s perspectives on participation in a DOE Clean Coal Technology demonstration project. A key conclusion for SPPCo. was that a project such as Piñon can provide a viable and acceptable balance considering costs; environmental performance, and environmental engineering leadership; technical risks and other factors. The strength and commitment of our commercial partners, and fuel flexibility of the proposed configuration were key aspects of an overall risk mitigation strategy.

## INTRODUCTION

Public Law 101-121 provided $600 million to conduct a fourth round of federally cost-shared Clean Coal Technology (CCT) projects to demonstrate technologies capable of replacing, retrofitting or repowering existing facilities. Following three previous solicitations in 1986, 1988, and 1989, DOE issued a Program Opportunity Notice (PON) for CCT-IV in January 1991, soliciting proposals to demonstrate innovative, clean, and energy efficient technologies capable of being commercialized in the 1990's. These technologies were to be capable of (1) achieving significant reduction in the emissions of sulfur dioxide and/or nitrogen oxides from existing facilities and/or (2) providing for future energy needs in an environmentally acceptable manner.

Sierra Pacific Power Company (SPPCo.) submitted a proposal in May 1991 in response to the CCT-IV PON requesting 50% co-funding of the Piñon Pine Power Project. SPPCo.'s proposal was for the design, engineering, construction, and operation of a nominal 800 ton-per-day (86 MWe gross), air-blown integrated gasification combined cycle (IGCC) project to be constructed at SPPCo.'s existing Tracy Station, a 244 MW, gas/oil-fired power generation facility located on a rural 400-acre plot about 20 miles east of Reno (see **Figure 1**). SPPCo. will own and operate the demonstration plant, which will provide power to the electric grid to meet its customer needs.



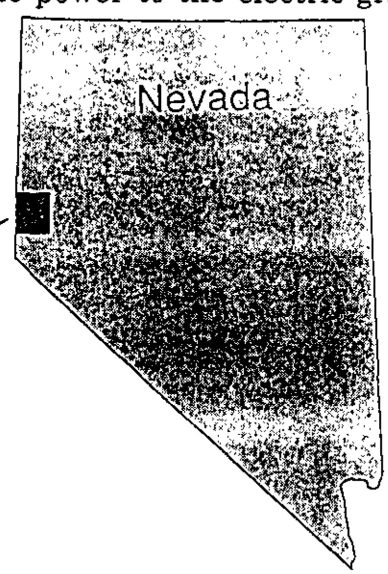




**Figure 1. Location of Proposed Piñon Pine Power Project.**

Of the 33 proposals submitted to DOE under CCT-IV, 9 proposals, including Piñon were selected for award. Following several months of negotiations, and Congressional Review of the proposed project, a Cooperative Agreement was executed. The project, including the demonstration phase, is scheduled to take 96 months at a total cost of $269,993,100. SPPCo. and DOE will share equally in project costs, in the amount of $134,996,550 each. Of this approximately $135 million, SPPCo. is projecting a capital cost of roughly $92 million, with the remaining $43 million being used for fuel and operations & maintenance expenses during the demonstration phase.

SPPCo will contract with Foster Wheeler USA Corporation (FWUSA) for the engineering, procurement and construction of the project. FWUSA in turn will subcontract with The M.W. Kellogg Company for engineering and other services related to the gasifier island. **Figure 2** depicts the project organization.

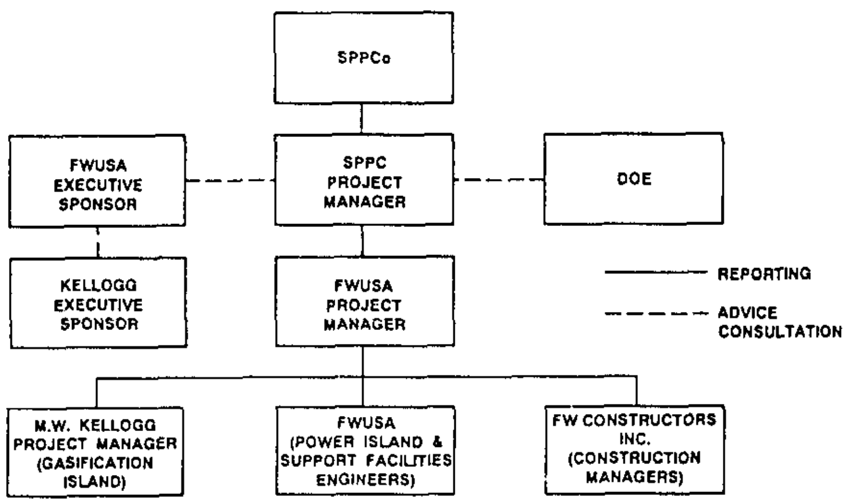


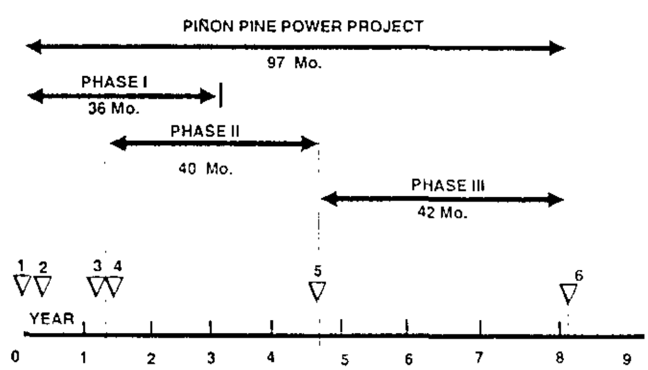

Figure 2. **Project Organization Chart.**

## PROJECT OBJECTIVES AND SCHEDULE

SPPCo.'s objective in the Piñon Pine Power Project is to use advanced technologies to produce a clean and low-cost power supply to meet our growing customer needs. Additional goals of the project are to demonstrate air-blown, pressurized fluidized-bed IGCC technology incorporating hot gas cleanup; to evaluate a low-Btu gas combustion turbine; and to assess long-term reliability, maintainability, and environmental performance at a scale sufficient to demonstrate further commercial potential. The plant will also provide economic benefits to the state and local community through employment and increase in the tax base. The project is expected to employ a construction workforce of 300-350 during peak construction years of 1994-1996. Once complete, the plant will provide about 25 new permanent jobs.

Federal funding of the project automatically invokes environmental review under the National Environmental Policy Act (NEPA). This project will require an Environmental Impact Statement, or EIS, with DOE as the lead agency for the NEPA reviews. The project must also be approved by the Nevada Public Service Commission (PSCN) in the state's Resource Planning process. To date, milestones that have been met include publication of the Notice of Intent in June, Public Scoping Meetings in July of 1992, and the submission of SPPCo.'s Resource Plan to the PSCN, with the project included as part of the Recommended Resource Plan. A PSCN decision on the project is expected in November, 1992. SPPCo. has also completed an Environmental Information Volume for the project, and expects a favorable Record of Decision by late 1993.

As shown in the project schedule below, SPPCo. expects to have the combustion turbine portion of the plant on line by late 1994, configured as a simple-cycle natural gas machine with either #2 diesel or propane being utilized as backup fuel. The gasifier, heat recovery steam generator (HRSG), and the balance of the IGCC plant will be commissioned in late 1996. By phasing construction in this manner, SPPCo. gains approximately 45 MWe of peaking power capacity to match projections of customer loads. A DOE demonstration period of 42 months is planned.




MILESTONES
1. Project Start/DOE Signs Agreement (8/92)
2. Resource Plan Approval (11/92)
3. Definitive Estimate/NEPA Complete (9/93)
4. UEPA Complete (12/93)
5. Construction/Commissioning/Start-Up Complete (3/97)
6. Testing Complete (9/00)

**Figure 3. Project Schedule.**

## SUMMARY OF TECHNOLOGY

### Overview

The Piñon Pine IGCC is similar to, and improves upon, first generation IGCC technology in several aspects. The Piñon Pine Project integrates a number of technologies fostered by the DOE. Among these are the KRW Energy Systems fluidized bed gasifier, with in-bed desulfurization, using limestone sorbent, and zinc ferrite (or zinc titanate) sulfur removal from a hot fuel gas stream. SPPCo. believes the project's pressurized, air-blown fluidized-bed gasification technology with hot-gas cleanup may provide an attractive alternative for new electric generating plants for several reasons:

- Air-blown gasification offers several potential advantages over commercially available oxygen-blown systems:
  - lower capital cost by eliminating the need for an oxygen plant
  - higher plant efficiency and lower capital costs by eliminating oxygen plant power consumption; and
  - inherent control of nitrogen oxide emissions (NOx) which may eliminate the need for a two-stage combustor or selective catalytic reduction (SCR)

- Hot gas cleanup is an attractive alternative to "cold" or "wet" chemical cleanup and offers several potential advantages.
  - hot gas sorbents can operate dry, thus eliminating the need for wastewater treatment; and
  - the dry cleanup process are generally more familiar to the utility industry than wet chemical systems.
- Components of the simplified IGCC are modular and fewer, thus providing better economy at small plant sizes.

The demonstration of the advanced IGCC technology will include actual integration of the gasifier with a combined cycle power plant. This step is necessary in order to evaluate the adequacy of integrated control concepts and measure actual performance of a complete power generation system on a utility grid. The modular concept of the proposed technology will provide information directly applicable to other commercial plants, since such plants will essentially incorporate one or more replicates of the demonstration project plant configuration.

Process Description

Raw coal will be received at the plant in weekly unit trains consisting of 100-ton automated bottom dumping railcars. Once unloaded, coal will be stored and transported within enclosures to minimize dust emissions. The coal is received and stored as 2" x 0 and is then transferred to a preparation area where it is crushed, dried, sized and passed to a day-bin for feeding the gasifier island. Sized limestone and dried coke breeze (for startup) are received by covered truck and are also stored in silos close to the gasifier island.

The two major components of the plant are the gasification island and the power island. **Figure 4** is a block diagram of the processes to be employed in the Piñon project.

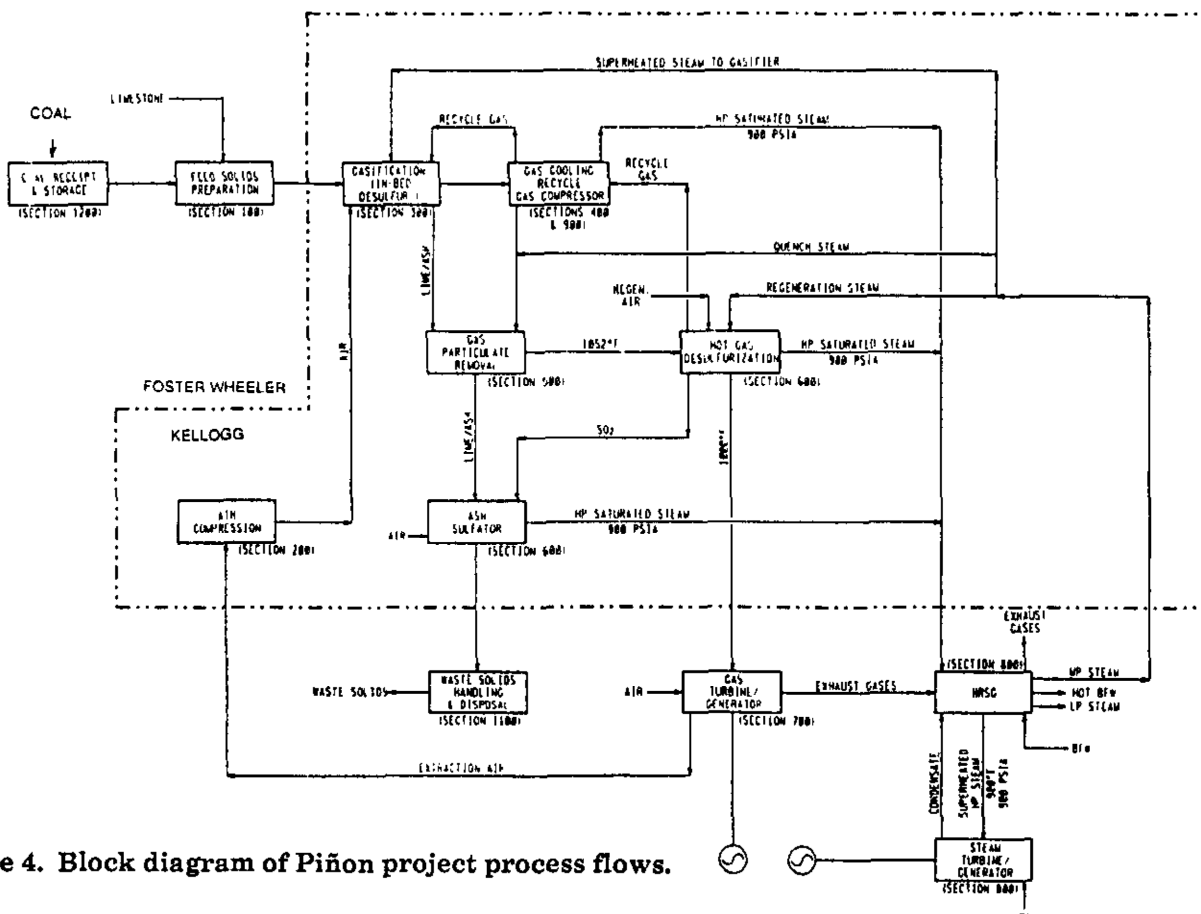



**Figure 4. Block diagram of Piñon project process flows.**

In the gasification island, crushed and sized coal and limestone are metered through lockhoppers and fed pneumatically through a central feed tube in the bottom of the gasifier. The temperature of the bed is controlled by metering the air and steam into the gasifier's central jet. The coal/limestone bed is maintained in a fluidized state in the gasifier via gas recirculation. Partial combustion of char (devolatilized coal) and gas occurs within the bed to provide the heat necessary for the endothermic reactions of devolatilization, gasification, calcination, and desulfurization. Ash and spent limestone are removed from the bottom of the bed.

The coal gas leaving the gasifier passes through a cyclone to remove the majority of the particulate matter that is returned to the fluidized bed. The gas leaving the gasifier is cooled to about 1050° F. before entering the hot gas cleanup section. Ceramic candle filters remove essentially all the remaining particulate material prior to the clean gas entering the sulfur sorbent bed. In the desulfurizing reactors, nearly all the remaining sulfur compounds are removed in a fixed bed of zinc ferrite sorbent. Zinc titanate is currently being tested in cooperation with DOE-METC and The M. W. Kellogg Company, and may be used in place of the zinc ferrite. The zinc ferrite (or titanate) is subsequently regenerated with steam and air. This process sends the regenerator gas stream to the sulfator where the sulfur oxides react with lime and air to form calcium sulfate, which exits the system along with the coal ash in a form suitable for landfill, or potentially to be used as a commercial byproduct.

In the power island, the clean coal gas will be delivered to a Westinghouse CW251 B12 combustion turbine, which is coupled to an electric generator designed to produce approximately 56 MWe (gross). Special turbine first stage blades will accommodate the extra mass flow produced by the low-Btu gas (as low as 90-95 Btu per standard cubic foot). The heat recovery steam generator (HRSG) receives high pressure steam from the gasifier island slightly above saturation, and uses the exhaust gas from the combustion turbine to superheat the steam as well as to generate additional high pressure steam. The steam is heated to 900° F. and 900 psig for expansion in a non-reheat steam turbine to produce approximately 30 MWe (gross). High pressure boiler feed water is circulated to the sulfator and the gasifier's product gas cooler. Steam at 400 psia is used in the gasifier island for the gasification reactions, gas quenching, and sorbent regeneration and is generated in the HRSG and/or by extraction from the steam turbine. Steam is also produced at 50 psia for various auxiliary plant purposes.

## UTILITY CONSIDERATIONS IN CCT DEMONSTRATIONS

A number of factors persuaded Sierra Pacific Power Company to participate in this clean coal technology demonstration project. The effect of the combination of these factors was compelling, leading to SPPCo.'s participation in the CCT program with the Piñon project.

Need for the power

SPPCo. has experienced strong load growth in recent years. Over the past ten years, system sales have grown at an annual rate of 5%. Load growth between 1992 and 1997, even considering an aggressive program of demand-side measures, is forecast to increase at an average rate of 4%, which will result in a need for 227 MWe of new capacity by the year 2000. Thus the capacity associated with Piñon is needed; however if capacity alone were the driving force, SPPCo. would be more likely be considering only resources such as combustion turbines, with a substantially lower cost per MWe of installed capacity.

Project Costs - Relationship to "Least Cost" Resource Planning

SPPCo. has conducted internal "Resource Planning" for decades to assess and best meet its customers needs for electrical power. In 1983 the Nevada Legislature added Resource Planning requirements to Nevada Statutes. The administrative regulations implementing that decision, called Nevada General Order 43 (or simply "G.O. 43") presented a comprehensive set of guidelines for conducting Resource Planning. These were adopted in early 1984, and have been revised several times since. The intent of G.O. 43 was (and still is) to ensure that load forecasts were as accurate as possible, that all appropriate demand-side and supply side options were considered, and that the preferred plan recommended by Nevada utilities for meeting their customer loads was developed and implemented in a "least-cost" manner. A "least-cost" plan was one that minimized the present value of revenue requirements, although the utility may also consider other factors such as reliability, financial constraints, fuel mix, environmental factors, etc. (As discussed in more detail below, Resource Planning regulations were subsequently modified to quantify the consideration of environmental and economic impacts of specific plans.)

In preparing SPPCo.'s mandatory 3-year Electric Resource Plan submittal which the Company filed on July 1, 1992, Piñon was modeled as one of the possible generation options. A key finding was that under a relatively broad range of economic assumptions, Piñon, in part due to the DOE support of this demonstration, was selected as part of the "least cost" plan for meeting future customer needs. Consequently, SPPCo. included Piñon as an integral part of it's latest Resource Plan, and requested approval from the Public Service Commission of Nevada. The Company expects a favorable decision on the project in November of this year, when the Commission issues it's "Opinion and Order" on the Resource Plan submittal. (In addition to Piñon, the Company has also recommended a simple-cycle combustion turbine and significant additional demand-side programs to be added within the next three year period.)

Environmental Factors

SPPCo. and its management place a high level of importance on protecting and/or improving the environment. The Company recently strengthened that commitment through the adoption of the "Company's Statement on Commitment to the Environment", approved by our Board of Directors. This document contains policy and action elements directing the company to make decisions that seek to integrate engineering, economics, and the environment in all of its decision processes. A major directive from the Company's top management was that, for the Piñon project to proceed, it not only comply with, but be a major contributor to SPPCo.'s goal to demonstrate excellence in environmental execution of all aspects of its business.

Nevada has recently modified its Resource Planning regulations to quantify and consider the value of so-called "environmental externalities"--adders to the present value of revenue requirements designed to capture all of the social or external costs from emissions, and economic benefits from employment, taxes, etc. A detailed discussion of these environmental externalities, and their incorporation in least-cost resource planning (as required in Nevada General Order 65), is beyond the scope of this paper, but will be presented in some detail by Jack McGinley , SPPCo.'s Supervisor of Supply Engineering at the upcoming Pittsburgh Coal Conference.

A fundamental issue associated with the decision to propose construction of any coal-burning powerplant, even a "clean coal technology" project is just how "clean" is the power? Piñon will have emissions among the lowest for any coal-fired powerplant, and will be substantially cleaner than any pulverized-coal plants. Even with these state-of-the-art clean coal technologies embodied in all aspects of Piñon (including the conventional portions such as coal handling), the project will still have minimal emissions of NOx, SOx, and particulates. Why not then build only geothermal, solar, or even natural gas fired units? The answer comes down to balance. Consideration of all factors, including the Company's commitment to the environment, but also addressing our obligation to provide reliable service at reasonable rates, the desirability of maintaining a diverse fuel mix, our already heavy dependence on alternative energy [by 1996, about 17% of our energy will be from geothermal power], and the aspects of leadership in environmental engineering were compelling in reaching the decision to proceed with this project.

Fuels Considerations

As discussed above, the KRW-IGCC technology has significant fuel flexibility. The Piñon project will be designed to be capable of operation on at least three fuels, including coal, natural gas, and either #2 distillate oil or propane. Other fuels may be considered as potential feedstocks later. The ability to burn a variety of fuels is important for several reasons.

Coal is the most abundant fuel in the United States. Use of this fuel, as well as being economically advantageous, also reduces dependence on foreign oil. Natural gas, at least in SPPCo.'s service area suffers from deliverability constraints (SPPCo. is currently curtailed through much of the winter for power generation applications.) Depletion of the current natural gas "bubble" (or "sausage", depending on your point of view) may result in significant real price increases in that commodity. Although coal is projected to be a least-cost fuel well into the future, forecasters have been known, although rarely, to be off the mark. Piñon will provide a long-term ability to use the most economic fuel, as well as to provide an alternate fuel in the event of disruptions such as a strike which could interrupt coal deliveries, or during periods when the gasifier island requires maintenance or service.

Project Risks and Risk Mitigation

Any technology has a certain intrinsic level of associated technical risk. The Piñon project is no exception. Utilities by nature generally tend to be risk averse. Cofunding of CCT programs by the DOE is one important way of mitigating financial risk. As SPPCo.'s President and CEO, Mr. William L. Keepers has stated:

> "As members of a regulated and highly competitive industry, electric utilities have a very limited ability to finance the development and demonstration of new technology. New generating technologies' demonstrations require significant first time costs. Given these circumstances, it is appropriate that the Clean Coal Technology Program provides a means for the U.S. consumer to share in the development, demonstration and benefits of this new technology. Our view of the potential for this technology and its highly probable success makes us confident that it will benefit our customers in California and Nevada for many years into the future."

In addition to financial cost-sharing to the project by the DOE--other factors exist which tend to mitigate the not-insignificant challenges and risks associated with a major demonstration such as Piñon. These include: (1) fully conventional, proven technology that constitutes much of the plant, (2) an ability to utilize any one of several different fuels, and (3) the technical strength and expertise of SPPCo.'s industrial associates in the project.

Much of the plant will be fully conventional, and is expected to have negligible to very low technical risk. Apart from the gasification system, the plant will be a conventional, fully functional combined cycle power plant capable of operation on natural gas and either distillate oil or propane. For these areas of the plant, full scale plant data is available, the operational aspects are well defined, and no significant design assumptions are required. The major portions of the plant that fit this low risk category are the coal receipt, coal preparation, and the entire gas/oil fired conventional combined cycle portions of the plant, including the combustion turbogenerator, HRSG, steam turbogenerator, condensor and heat rejection system, as well as plant auxiliaries.

The "demonstration" portions of the plant are more developmental in nature and involve scaleup from pilot plant quality data, design assumptions based on limited data, or significantly different application of a technology. Experience with the KRW technology dates back to 1972 when the government first funded design of a process development plant at Westinghouse Electric Corporation's Waltz Mill facility near Madison, PA. This pilot unit demonstrated successful operation of the air-blown fluidized bed gasification process on a wide variety of coals, and included testing of in-bed desulfurization, and operation with ceramic candle filters and external hot gas desulfurization. The four areas of the gasification system and hot gas cleanup systems having a moderate level of technical risk are: (1) gasifier and in-bed desulfurization, (2) gas conditioning, filtration and external desulfurization, (3) low Btu gas combustor and controls, and (4) fluidized bed sulfator.

Finally, the technical strength, experience and commitment of both Foster Wheeler USA and The M. W. Kellogg Company as industrial allies in this project were significant factors in decreasing SPPCo.'s risk associated with the construction of a project such as Piñon. Westinghouse, the supplier of the combustion turbine for this project has extensive experience with coal based IGCC including very low Btu content fuel gas, and, as noted above, has been associated with the KRW technology from its inception. The expertise and commitment of these firms will be critical factors in making this project a success.

Also critical to the success of this project is the support of our customers and regulators. Although the project has some risks, SPPCo. believes that they are manageable, and more than offset by the benefits expected to accrue to our ratepaying customers. The Company has requested approval from our regulators for this important project, and will be requesting fair and appropriate treatment of the expenses incurred.

## SUMMARY

The Piñon Power Project is a major, 80 MWe project with the dual objectives of providing environmentally clean, economic power to serve SPPCo.'s customers while demonstrating an innovative clean coal technology which we believe offers significant environmental and economic benefits over existing IGCC technologies. The air-blown, agglomerating fluidized bed IGCC technology, coupled with hot gas clean up using mixed metal oxide sulfur sorbents, offers the potential of lower capital and operating costs than first-generation IGCC technologies, and is coupled with superior environmental advantages over conventional coal technologies. SPPCo. believes that the technical merits of the project, along with cost sharing of this demonstration by DOE, the technical expertise and support of Foster Wheeler USA, The M.W. Kellogg Company, and Westinghouse Corporation will make this exciting project a success.

## GLOSSARY:

| | |
|---|---|
| Btu | British Thermal Unit, a measure of heat capable of raising 1 pound of water by 1° F. |
| CCT | Clean Coal Technology Program (DOE) |
| DOE | U. S. Department of Energy |
| HRSG | Heat Recovery Steam Generator, a boiler extracting heat from the exhaust gas stream from the combustion turbine |
| IGCC | Integrated (coal) Gasification Combined Cycle, a technology for converting coal to a fuel gas, removing particulates and sulfur from the gas, and converting the gas to electricity in a process employing both gas turbine (Brayton thermodynamic cycle) and steam turbine (Rankine cycle) generators. |
| METC | Morgantown Energy Technology Center, West Virginia |
| MWe | Megawatts, electric |
| psia: | Pounds per square inch, absolute pressure |
| psig: | Pounds per square inch, gauge pressure |
| tpd | Tons per day |

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# DMEC-1 Pressurized Circulating Fluidized Bed Demonstration Project

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## INTRODUCTION

The Des Moines Energy Center (DMEC) project will be the first commercial scale demonstration of Pyropower's PYROFLOW® Pressurized Circulating Fluidized Bed (PCFB) technology for electric utility power generation. The project will employ the PCFB technology to repower an existing steam turbine at the DMEC site.

### Technology Overview

In the PCFB process, the compressor section of a gas turbine provides pressurized air to a pressure vessel in which a circulating fluidized bed combustor is installed. In the combustor, fuel and sorbent are mixed with the air and combustion takes place at about 1600 F. The heat generated is removed from the flue gas to produce steam which is used to drive an existing steam turbine generator. Fuel and sorbent particles are separated from the gas stream in a hot cyclone and are returned to the combustor. Finer particles of fully reacted sorbent and ash are removed in a ceramic barrier filter. The now cleaned gas is expanded through the gas turbine producing mechanical power to drive the compressor and to generate additional electrical power. Finally, the remaining useful heat is extracted from the flue gas and used in the feedwater heating system. A simplified diagram of this process is shown in Figure 1.

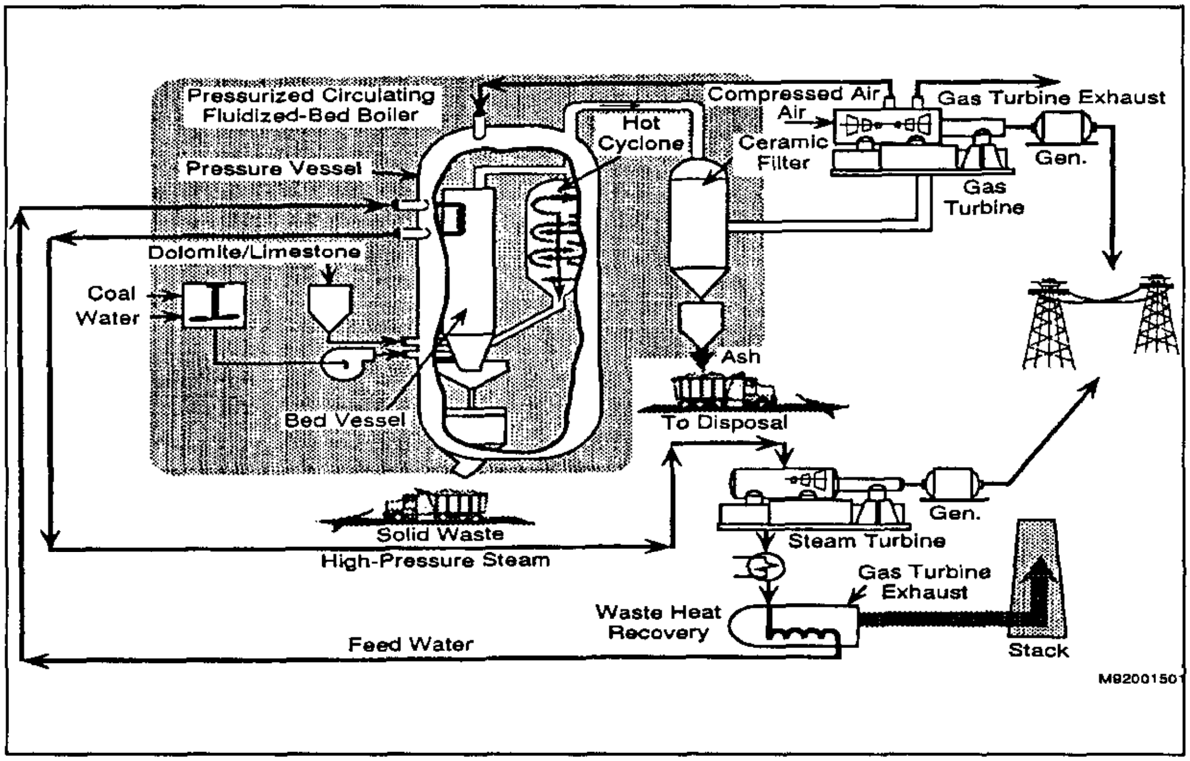


Figure 1- PCFB Simplified Process Diagram

## Project Goals

The goals of the project are to demonstrate the following features of PCFB technology:

- Lower Capital Cost. The PCFB is anticipated to cost about 10 percent less on an installed plant basis than an atmospheric CFB or pulverized coal plant with scrubbers.

- High Efficiency and Reduced $CO_2$ Emissions. The PCFB will convert an existing power plant to a combined cycle generating station resulting in a net heat rate improvement of approximately 15 percent.

- Reduced Space Requirements. The PCFB furnace and ceramic filter will require substantially less space than other power generation technologies, and so are a preferred alternative for repowering applications.

- Shop Fabrication. Due to reduced equipment sizes, components of the PCFB can be shop fabricated. This will enhance equipment quality and reduce field construction time.

- Lower Mechanical Complexity. Fewer fuel and sorbent feed points will reduce mechanical complexity and improve the opportunity for redundancy.

- Hot Gas Cleanup Technology. The PCFB system will include a ceramic filter designed to remove over 99 percent of the particulate upstream of the gas turbine. This will provide for protection of the gas turbine from erosion as well as compliance with particulate emission requirements without additional particulate removal systems.

- No Exposed Surfaces in the Lower Combustor. The lower section of the PCFB combustor is refractory lined and contains no exposed heat transfer surfaces providing a region for safe slumping of the bed during shutdown.

- Control of $NO_x$ and Furnace Temperature. Air is fed to the combustor as primary and secondary air. This splitting of air helps reduce formation of $NO_x$ and provides a means of controlling furnace temperature.

- Control of $SO_x$ and CO. The PCFB is designed to meet New Source Performance Standards for emissions of all regulated pollutants including $SO_x$, $NO_x$, CO and particulate, without the need for backend emissions control devices such as scrubbers.

- Simplified Load Following. Load following in the PCFB is accomplished by varying fuel feed rate and primary/secondary air ratio in the combustor. It is not necessary to vary solids inventory for this purpose as is required in bubbling pressurized bed designs.

- Erosion Prevention. The PCFB will utilize Double Omega Surface for superheating steam in the combustion chamber. This design greatly reduces the potential for erosion of these surfaces.

- Capacity Edition. The PCFB used in a repowering application provides the opportunity to increase plant capacity at an existing site by 20 to 30 percent.

Project Organization

The DMEC-1 limited partnership with Dairyland Power as the limited partner and Midwest Power, formerly Iowa Power, as the general partner will be the participant for the project. The project was selected in the Clean Coal Technology Round 3 solicitation. The partnership has signed the Cooperative Agreement with the DOE. In addition to the participant, the project team consists of Pyropower and Black & Veatch.

Pyropower Corporation of San Diego, Ca. will provide the PCFB equipment. In addition they will provide component testing and support during startup and the demonstration. Black & Veatch of Kansas City, Mo. will provide engineering and design services for the balance of plant and construction management services.

Site Description

The Des Moines Energy Center is located southeast of the city of Des Moines, Iowa in the city of Pleasant Hill, Iowa. DMEC is located adjacent to this Des Moines river and highway 46. The site occupies approximately 50 acres with an additional 100 acres east of highway 46 used for ash disposal. An existing substation east of the plant buildings provides a connection to the Midwest Power electrical system.

The repowering in this project involves the restoration of a steam supply system to the existing steam turbine generator known as Unit 6. The unit will be renamed DMEC Unit 1.

Project Cost and Schedule

The project is divided into three phases and four budget periods as follows:

- Phase 1: Design
  - Budget Period 1 - Preliminary design 8/91 to 6/93
  - Budget Period 2 - Detailed design 7/93 to 6/94
- Phase 2: Construction
  - Budget Period 3 - Construction 7/94 to 5/96
- Phase 3: Operation
  - Budget Period 4 - Operation 6/96 to 6/98

The estimated project cost including the demonstration phase is as follows:

| | |
|---|---|
| DOE Share | $ 93,253,000 |
| Participant Share | $109,706,000 |
| Total | $202,959,000 |

The participant share includes contributions by Midwest Power, Pyropower and Black and Veatch and in-kind contributions by Midwest Power, Dairyland Power, and Pyropower. The total cost includes engineering, fabrication, construction, and allowances for escalation. Also included are operations and testing costs for the operating phase.

Following the operating phase, the plant will continue operation as a part of Midwest Power's generation resources.

## TECHNOLOGY DESCRIPTION

The DMEC-1 project will employ the Pyropower PYROFLOW PCFB process. Brief descriptions of the process systems follows.

Coal Feed System

The coal feed system is comprised of two systems designed to be 100 percent redundant when operated on western coal. Each system includes a gravimetric feeder at the bottom of a coal silo. The feeders feed coal to a two-stage coal/water paste preparation system. Each secondary mixer feeds two paste pumps. The paste pumps pressurize the mixture to force the paste through the feed lines to the PCFB combustor. The paste pumps are piston-type pumps used in applications such as concrete pumping.

As the paste enters the combustor, atomization will be used to evenly distribute the fuel in the lower combustor. Because of the enhanced mixing that occurs in the circulating fluidized bed system, a total of only four fuel feed points is anticipated.

Sorbent Feed System

The sorbent feed system will deliver properly sized limestone or dolomite to the PCFB combustor for control of $SO_2$ emissions. Crushed sorbent will be blown into storage silos and fed by gravity to lock hoppers. It is expected that the majority of the sorbent will be fed to the combustor by mixing with the coal/water slurry. Some sorbent will be fed through a pressurized lock hopper system to trim the process when $SO_2$ emission variations occur due to variations in fuel sulfur content, sorbent quality, or process upsets. A separate sand lock hopper will be provided to load a charge of bed inventory into the combustor.

PCFB Hot Loop

The hot loop, the heart of the PCFB process, is comprised of the combustor, the hot cyclones, the loop seal returns, and the water and steam cooled heat transfer surfaces.

Pressurized coal and sorbent are fed into the lower PCFB combustor at about 200 psig. The combustor uses membrane wall construction. Natural circulation from the drum through downcomers cools the waterwalls. The lower section of the combustor is lined with refractory to protect it from erosion during operation and to provide a region for safe slumping of the bed during shutdown.

Primary air, which comprises about 60 percent of the total air, is fed to the combustor through the startup burners and grid. This air fluidizes and mixes the fuel and sorbent. The remaining 40 percent of the air, secondary air, is injected at points higher in the combustor. Use of split air streams provides the following:

- Combustor temperature control
- Minimal $NO_x$ formation
- Improved solids mixing and circulation
- Air for fines combustion in the upper part of the combustor
- Improved load following capability

As the fuel is burned and the sorbent reacts with $SO_2$, the smaller solid particles are entrained with the upward flow of combustor gases. The hot gas and solids enter the hot cyclones where 90 percent of the entrained particles are collected and recirculated to the combustor through the loop seals. Pressurized air from a booster compressor is injected in the loop seals to refluidize the collected solids and return them to the combustor. The residence time obtained from this collection and recirculation promotes improved combustion efficiency and $SO_2$ removal.

Saturated steam generated in the water cooled membrane walls is superheated in the Double Omega platen surfaces located in the middle and upper sections of the combustor. The Double Omega tube design minimizes erosion of these heat transfer surfaces and has been successfully used in atmospheric Pyropower boilers.

Pressure Containment

The pressure vessel which encloses the PCFB hot loop is a conventional pressure vessel.

The combustor and hot cyclones are suspended from the top of the vessel. Platforms and ladders necessary for access to these components are mounted inside.

### Ceramic Filter

Flue gas from the hot cyclones proceeds to the ceramic filter where the remaining fly ash and reacted sorbent are collected. By using this hot gas cleanup technology, no further particulate removal is required to meet the requirements for the gas turbine protection. In addition atmospheric particulate emission limits are met. Cleaning of the ceramic elements is accomplished by injection of reverse pulses of pressurized air causing a mild shock wave sufficient to release the collected dust .

### Hot Ash Depressurization and Cooling System

Hot ash is removed at two locations, from the hot loop and from the ceramic filter. Removal is accomplished by use of water cooled pressurized screw conveyors and lock hoppers. Both systems will be designed for 100 percent redundancy.

### Heat Recovery Economizer

The heat recovery economizer is designed to remove the remaining useful heat from the gas turbine exhaust gases. The flue gas at the turbine exhaust are atmospheric pressure and at approximately 800 F. The economizer is a conventional smooth tube and finned-tube design.

### Gas Turbine

The compressor section of the gas turbine provides pressurized combustion air to the PCFB combustor. The hot flue gases from the ceramic filter are expanded through the turbine section of the gas turbine to produce mechanical energy to drive the compressor and an attached electrical generator. It is expected that the most significant modification to a conventional gas turbine for this application will be to allow the use of the external PCFB combustor.

High temperature valves are provided upstream of the gas turbine to provide for emergency shutdown of the gas turbine. Redundant systems will be employed to ensure safe performance of these valves.

## DEVELOPMENT HISTORY

### Karhula Testing Facility

The Karhula PCFB Testing Facility was built in Karhula, Finland to support the design and operation of commercial first generation and Advanced PCFB units. In 1989, Ahlstrom, the parent company of Pyropower, initiated operation of the Karhula PCFB Testing Facility. It is an integrated PCFB unit, including all of the key PCFB components and incorporating the same mechanical design features which will be utilized in commercial plants. These include complete fuel handling and preparation systems, sorbent injection systems, pressurized furnace with radiant heat transfer surfaces, hot cyclone, ceramic filter, ash cooling and depressurization systems, and testing of materials and coatings for gas turbine blades. At the 10 MWt scale, the Karhula facility operates at the same conditions as a commercial process plant. The conditions include combustor operating pressure and temperature, fluidizing velocity, arrangement of heat transfer surfaces, heat transfer rates, solids distribution, emissions control, and residence times.

The PCFB - Filter test facility is designed for the following operating conditions:

| | | | |
|---|---|---|---|
| • | Heat Input | 34 mmBtu/hr | (10 MWth) |
| • | Fuel Feed Rate (max) | 15870 lb/hr | (2 kg/s) |
| • | Gas Flow Rate (max) | 43650 lb/hr | (5.5 kg/s) |
| • | Operating Temperature | 1616 °F | (880 °C) |

- Operating Pressure (max) 232 psia (16 bar a)

Recently, Pyropower and Westinghouse Electric executed a contract for the testing of the Westinghouse Ceramic Candle Filter technology at Karhula. That program, which will test the Westinghouse Filter and Coor's Ceramic Filter Elements, has been cosponsored by American Electric Power and the DOE. Testing is expected to begin in the fall of 1992.

Test Facility Testing Program

The main objectives of the Karhula PCFB-Filter Testing facility program are:

- To generate process data for the design of commercial size PCFB units
- To develop engineering data for in-house and vendor engineering of PCFB systems and plant auxiliaries such as fuel feeding and ash handling
- To generate data base for auxiliary equipment performance which can be used for other advanced coal utilization technologies
- To demonstrate a commercial scale high-pressure high-temperature filter under PCFB conditions

Since summer of 1989, the Karhula PCFB Testing Facility has accumulated over 3000 hours of operation. A variety of coals have been burned including Polish Coal, Illinois No. 6 coal, Wyoming Sub-Bituminous Coal, and Australian Coal. Future tests with Pittsburgh No. 8 coal are also planned. Plant performance results have been very encouraging with repeatable sulfur emissions reductions as high as 95 - 99.5%, over 99.5% carbon conversion, and under 0.2 lb/MMBtu $NO_x$.

## INTEGRATION OF PCFB WITH EXISTING FACILITIES

In this project, an existing boiler will be replaced to repower an existing steam turbine. The steam turbine, manufactured by Westinghouse, was placed in service in 1954 and is rated at 60 MW. It is designed for superheated steam at 1250 psig and 950 F at a flow rate of 561,000 pounds per hour. The associated generator is a hydrogen cooled machine rated at 60 MW. As a part of the project the turbine generator subsystems will be refurbished or replaced as needed. Figure 2 shows how the PCFB will be integrated into the existing systems.

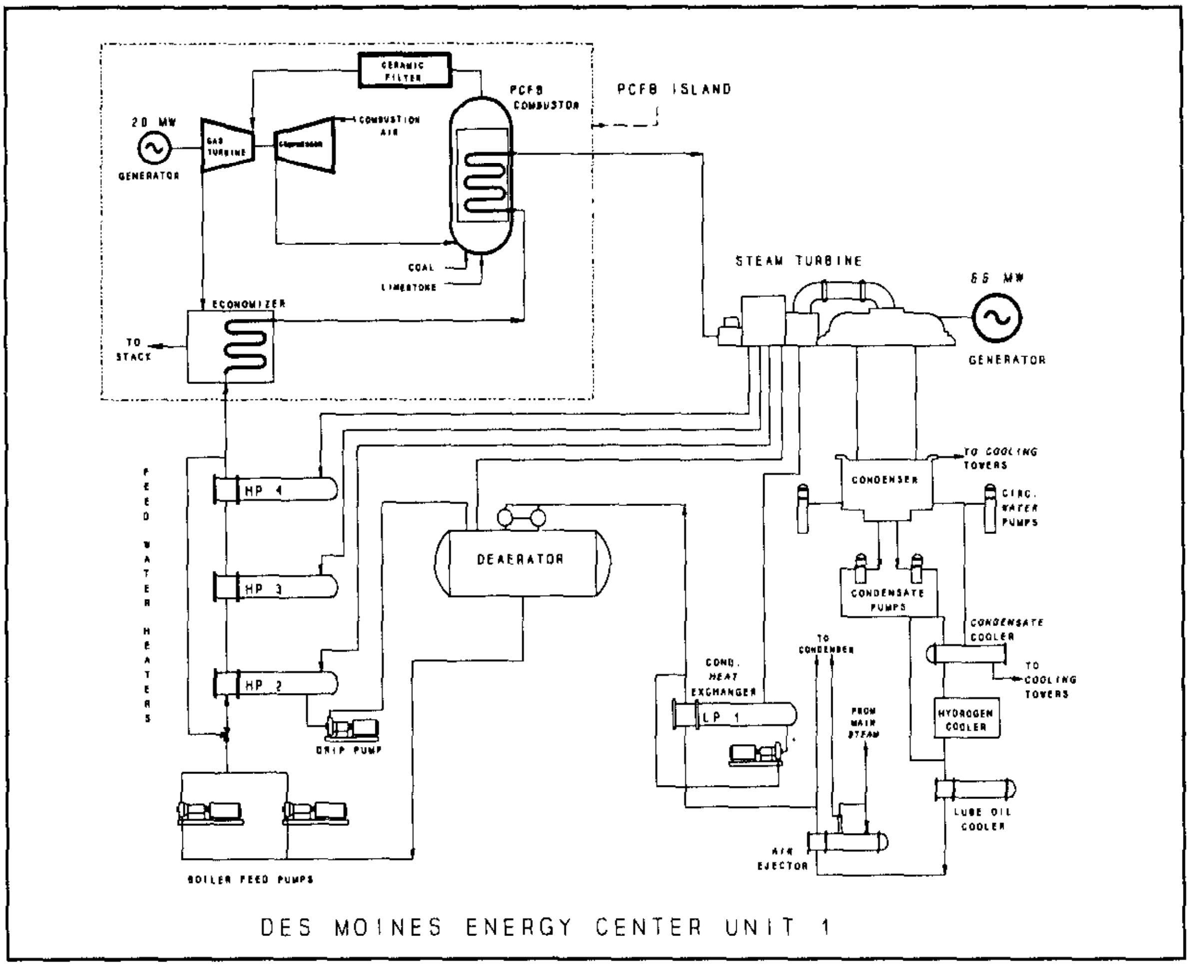


**Figure 2**- PCFB Connection to Existing Equipment at DMEC

In the existing cooling system, it is anticipated that the condenser will be refurbished and the cooling tower system will be replaced. The condensate system will be refurbished with some components such as the condensate pump motors requiring replacement.

## PROJECT TEAM AND ORGANIZATIONAL STRUCTURE

PSI will manage the construction of, own and operate the power generation facilities. Sargent & Lundy will provide engineering services to PSI. Destec will manage the construction of, own and operate the coal gasification facilities. Dow Engineering Company, engineer for Destec's 160 MW coal gasification facility operating in Louisiana, Louisiana Gasification Technology, Inc. ("LGTI"), will provide engineering services to Destec. Destec is in the process of transferring coal gasification engineering expertise from Dow to Destec Engineering Company and the Project will expedite this transition. PSI is currently working with the Electric Power Research Institute ("EPRI") to determine EPRI's role in the Project.

Two agreements establish the basis for the relationship between PSI and Destec. The Joint Venture Agreement established the Wabash River Coal Gasification Repowering Project Joint Venture in order to administer the Project under the DOE Cooperative Agreement. The Gasification Services Agreement includes the commercial terms under which the Project will be developed and operated for a minimum of 25 years. Major provisions of the Gasification Services Agreement include:

<u>PSI</u>

- to own and operate the power generation facility
- to furnish Destec with a site, coal, electric power and other utilities
- to pay a monthly fee to Destec for gasification services

<u>Destec</u>

- to own and operate the coal gasification facility
- to guarantee performance of the coal gasification facility
- to deliver syngas and steam to the power generation facility

The structure described in the Gasification Services Agreement allows the Project to be integrated for high efficiency and provides for the use of common facilities to eliminate duplication.

## PROJECT COST AND SCOPE

*Facilities for the Project include the following:*

Gasification Plant (Destec Facilities)

- Slurry preparation
- Gasification and heat recovery
- Slag removal
- Gas cleanup
- Sulfur recovery
- Oxygen facility
- Control room and buildings

Power Generation (PSI Facilities)

- Combustion turbine
- Heat recovery steam generator
- Modifications to coal handling, water plant and switchyard
- Oil storage tank
- Piping additions
- Control room and buildings

The total estimated capital cost for the Project is $407 million, of which Destec's and PSI's facilities are $285 million and $122 million, respectively. This cost includes escalation but not allowances for funds used during construction.

## PROJECT TECHNICAL DESCRIPTION

The Destec Coal Gasification process was originally developed by The Dow Chemical Company during the 1970's in order to diversify its fuel base. The technology being used at Wabash is an extension of the experience gained from that time through pilot plants and up to the LGTI facility at Plaquemine, Louisiana which has been operating since April 1987.

Coal is ground with water to form a slurry (see Figure 3). It is then pumped into a gasification vessel where oxygen is added to form a hot raw gas through partial combustion. Most of the noncarbon material in the coal melts and flows out the bottom of the vessel forming slag - a black, glassy, nonleaching, sand-like material. The hot, raw gas is then cooled in a heat exchanger to generate high pressure steam. Particulates, sulfur and other impurities are removed from the gas before combustion to make it acceptable fuel for the gas turbine.

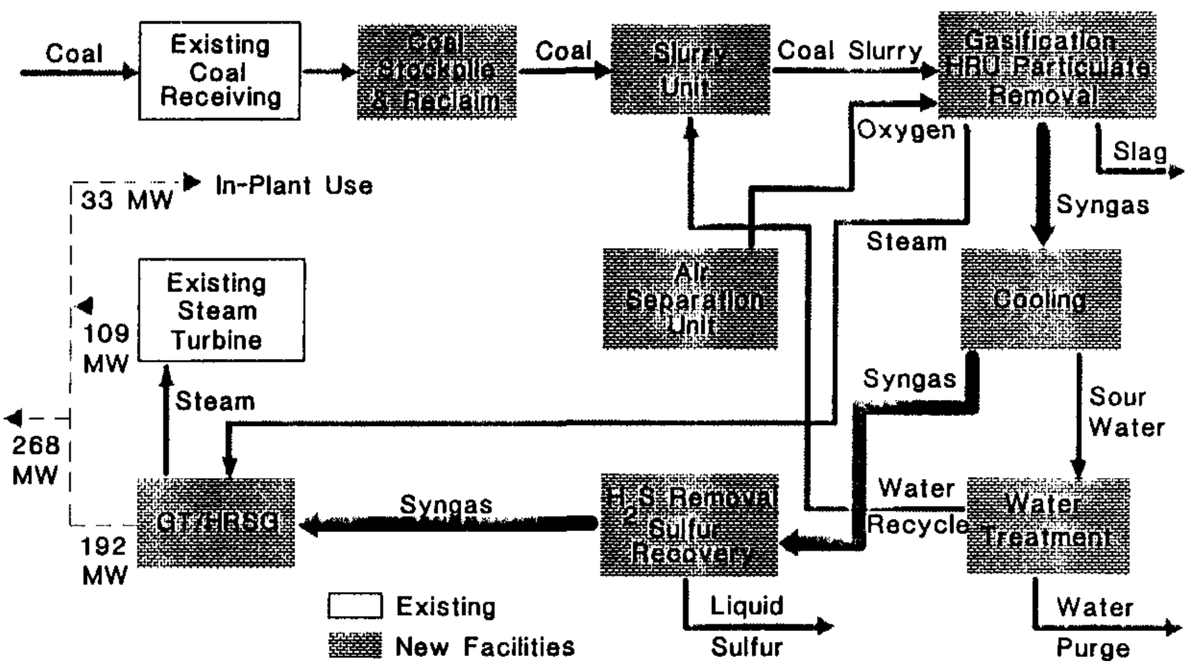


Figure 3. Block Flow Diagram

The synthetic fuel gas (syngas) is piped to a General Electric MS 7001F high temperature combustion turbine generator which produces approximately 192 MW of electricity. A heat recovery steam generator recovers gas turbine exhaust heat to produce high pressure steam. This steam and the steam generated in the gasification process supply an existing steam turbine-generator in PSI's plant to produce an additional 109 MW. Plant auxiliaries in the power generation and coal gasification areas consume approximately 33 MW, for a nominal net power generation for export of 268 MW. The expected net plant heat rate for the entire new and repowered unit is 8,974 Btu/KWH (HHV), representing approximately 20 percent improvement over the existing unit. The heat rate will be among the lowest of commercially operated coal-fired facilities in the United States.

In order to generate data necessary for commercialization, the Joint Venture has chosen a very ambitious approach for incorporation of novel technology in the Project. This approach is supported by PSI's desire to have another proven technology alternative available. Destec desires to enhance its competitive position relative to other clean coal technologies by demonstrating new techniques and process enhancements, gaining information as to operating costs and performance expectations. The incorporation of novel technology in the Project will enable utilities to make rational commercial decisions concerning the utilization of Destec's technology, especially in a repowering application.

New enhancements, techniques and other improvements included in the novel technology envelope for the Project are as follows:

- A novel application of integrated coal gasification combined cycle technology will be demonstrated at the Project for the first time . . . repowering of an existing coal-fired power generating unit.
- The coal fuel for the Project will be high sulfur bituminous coal, thus demonstrating the environmental performance and energy efficiency of Destec's advanced two-stage coal gasification process. Previous Destec technology development has focused on lower rank, more reactive coals.
- Hot/Dry particulate removal/recycle will be demonstrated at full commercial scale at the Project. Destec's current plant, operating in Louisiana, has utilized a wet scrubber system to remove particulates from the raw syngas.

Other coal gasification process enhancements included in the Project to improve the efficiency and environmental characteristics of the system are as follows:

- Syngas Recycle will provide fuel and process flexibility while maintaining high efficiency.

- A High Pressure Boiler will cool the hot raw gas by producing steam at a pressure of 1,600 pounds per square inch absolute (psia). Destec's first unit is currently operating at a pressure of 650 psia in a much less corrosive environment than will be experienced at the Project.
- The Carbonyl Sulfide ("COS") Hydrolysis system to be incorporated at the Project will be Destec's first application of this technology. This system is necessary to attain the high percent removal of sulfur at the Project.
- The Slag Fines Recycle system will recover most of the carbon present in the slag byproduct stream and recycle it back for enhanced carbon conversion. This also results in a high quality byproduct slag.
- Fuel Gas Moisturization will be accomplished at the Project by the use of low-level heat in a new concept different from that used before by Destec. This concept will reduce steam injection required for $NO_x$ control.
- Sour water, produced by condensation as the syngas is cooled, will be processed differently from the method used at LGTI. This novel Sour Water System, to be used at the Project, will allow more complete recycle of this stream, reducing waste water and increasing efficiency.
- An advanced design Oxygen plant producing 95 percent pure Oxygen will be used by the Project. This will increase the overall efficiency of the Project by lowering the power required for production of Oxygen.

The power generation facilities included in the Project will incorporate the latest advancements in combined cycle system design while accommodating design constraints necessary to repower the exiting Unit One steam turbine.

- The Project will incorporate an Advanced Gas Turbine with new design compressor and turbine stages, higher firing temperatures and higher pressure ratios.
- Integration Between the Heat Recovery Steam Generator ("HRSG") and the Gasification Facility has been optimized at the Project to yield higher efficiency and lower operating costs.

- Repowering of the Existing Steam Turbine will involve upgrading the unit in order to accept increased steam flows generated by the HRSG. In this manner, the cycle efficiency will be maximized because more of the available energy in the cycle will be utilized.

## PROJECT ENVIRONMENTAL ASPECTS

The plant will be designed to substantially outperform the standards established in the CAAA for the year 2000. The Destec technology to be employed will remove at least 98 percent of the sulfur in the coal. $SO_2$ emissions will be less than 0.20 pounds of $SO_2$ per million Btu's of fuel. $NO_x$ emissions from the Project will meet state and federal limits. Total $NO_x$ emissions from both the gasification block and the power block are expected to be less than 0.7 lb/MWh. $CO_2$ will also be reduced, approximately 21 percent on a per kilowatt-hour basis by virtue of the increased system efficiency. Figure 4 compares emissions of current Wabash Unit 1 with expected emissions from the Project.

| EXPECTED PROJECT EMISSIONS | $SO_2$ | $NO_x$ | CO | PM | PM-10 | VOC |
|---|---|---|---|---|---|---|
| Gasification Block Tons/yr | 23 | 18 | 124 | 25 | 20 | 12 |
| Power Block Tons/yr | 204 | 774 | 374 | 46 | 42 | 13 |
| TOTAL Tons/yr (Note 1) | 227 | 792 | 498 | 71 | 62 | 25 |
| Lb/MW hr | 0.21 | 0.75 | 0.47 | 0.07 | 0.06 | 0.02 |
| LB/MM Btu | 0.02 | 0.08 | 0.05 | 0.01 | 0.01 | 0.003 |
| CURRENT UNIT NO. 1 BOILER EMISSIONS | | | | | | |
| Tons/yr (Note 2) | 5,713 | 1,370 | 94 | 126 | 126 | 5 |
| Lb/MW hr | 38.2 | 9.3 | 0.64 | 0.85 | 0.85 | 0.03 |
| Lb/MM Btu | 3.1 | 0.8 | 0.05 | 0.07 | 0.07 | 0.003 |
| Note 1: | 2,111,160 MWhr estimated annual generation (268 MW at 90% *capacity factor*). | | | | | |
| Note 2: | 294,432 MW hr average annual actual gross generation for 1989 and 1990. *(approximately 37.3 capacity factor for Unit 1)* | | | | | |

**Figure 4. Project Emissions Comparison**

By providing an efficient, reliable and environmentally superior alternative to utilities for achieving compliance with the CAAA requirements, the Project will represent a significant demonstration of Clean Coal Technology.

The gasification process by-products, sulfur and slag, are also recyclable. Most of the noncarbon minerals in the coal are removed during the gasification process. Sulfur is removed as 99.7 percent pure elemental sulfur and can be sold as a raw material to make agricultural fertilizer. The remaining minerals leave the process chemically bound as slag which has been used as aggregate in asphalt roads and as structural fill in various types of construction applications.

**PROJECT PLAN AND SCHEDULE**

Initial discussions concerning the feasibility of repowering one of PSI's units took place in May of 1990. The Wabash site was selected as the preferred location because of the availability of space, the condition and size of the unit to be repowered and the fact that the unit was to be affected by the Clean Air Act amendments. In October 1990 PSI and Destec agreed to jointly develop the Project and submit a proposal in response to the DOE's Clean Coal IV solicitation. The proposal was submitted in May of 1991.

Cycle optimization studies, activities supporting environmental permits and preliminary geotechnical investigations took place through the summer of 1991 while the DOE was evaluating the Project's proposal. The DOE announced selection of the Project under the solicitation in September 1991. DOE negotiations were completed in May, 1992 and the National Environmental Policy Act ("NEPA") review is in progress.

In May 1992 application for approval of the Project was submitted to the Indiana Utility Regulatory Commission and environmental permit applications were submitted in June of 1992. The DOE signed the Cooperative Agreement on July 27, 1992 after the required Congressional review period.

Based on receipt of approvals, detailed engineering will be complete in 1993. Construction is scheduled to commence early 1993 with start-up early 1995. Full commercial operations will commence in mid-1995.

# STATUS OF TAMPA ELECTRIC COMPANY IGCC PROJECT

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## ABSTRACT

Tampa Electric Company will utilize Integrated Gasification Combined Cycle technology for its new Polk Power Station Unit #1. The project is partially funded under the Department of Energy Clean Coal Technology Program Round III. This paper describes the technology to be used, process details, demonstration of a new hot gas clean-up system, and the schedule, leading to commercial operation in July 1996.

## INTRODUCTION

Tampa Electric Company has begun engineering for its new Polk Power Station Unit #1. This will be the first unit at a new site and will use, Integrated Gasification Combined Cycle (IGCC) Technology. The unit will utilize oxygen-blown entrained-flow coal gasification, along with combined cycle technology, to provide nominal 260MW (net) baseload generation.

The project is partially funded by the U. S. Department of Energy (DOE) under Round III of its Clean Coal Technology Program. Use of a new hot gas clean-up system will highlight this demonstration of IGCC technology on a commercial scale.

## OBJECTIVE

Obviously, the main objective of any power plant is to provide electric power for the utility's Customers. This unit is an integral part of Tampa Electric Company's (TEC) generation expansion plan. That plan requires baseload capacity to be in service in the summer of 1996. TEC's objective is to build a coal-based generating unit providing reliable low cost electric power. Using IGCC technology will meet those requirements.

Demonstration of the oxygen-blown entrained-flow IGCC technology is expected to show that such plant can achieve significant reductions of $SO_2$ and $NO_x$ emissions when compared to existing and future conventional coal-fired power plants. In addition, this project is expected to demonstrate the technical feasibility of a commercial scale IGCC unit using hot gas clean-up technology.

## PROJECT PARTICIPANTS

### Tampa Electric Company

Tampa Electric Company (TEC) is an investor-owned electric utility, headquartered in Tampa, Florida. It is the principal, wholly owned subsidiary of TECO Energy, Inc., an energy related holding company heavily involved in coal mining, transportation, and utilization. TEC has about 3200MW of generating capacity, of which 97% is coal-fired. TEC serves about 470,000 Customers in an area of about 2,000 square miles in west-central Florida, primarily in and around Tampa, Florida.

TEC owns five generating stations; two are coal-fired (2852MW) two are oil-fired (253MW), and one is natural gas-fired (11MW). TEC also has four combustion turbines with about 160MW of generating capacity, used for start-up and peaking.

### TECO Power Services

TECO Power Services (TPS) is a subsidiary of TECO Energy, Inc., and an affiliate of TEC. This company was formed in the late 1980's to take advantage of the opportunities in the non-utility generation market. TPS is currently starting up a 295MW natural gas-fired combined cycle power plant in Hardee County, Florida. Seminole Electric Cooperative and Tampa Electric Company are purchasing the output of this plant under a twenty year power sales agreement.

TPS is responsible for the overall project management for the DOE portion of this IGCC project. TPS will also concentrate on commercialization of this IGCC technology, as part of the Cooperative Agreement with the U. S. Department of Energy.

U. S. Department of Energy

The Department of Energy has entered into a Cooperative Agreement with TEC under Round III of the Clean Coal Technology (CCT) Program. Project Management is based in DOE's Morgantown Energy Technology Center in West Virginia.

## THE SITE

The Polk Power Station will be built on an inland site in southwestern Polk County, Florida (Figure 1). The site, about 11 miles south of Mulberry, is a tract previously and currently mined for phosphate and is unreclaimed. This site was intended to be used for TEC's next generation addition, originally a 75MW combustion turbine (CT) scheduled to be in service in mid-1995. The site was selected by an independent Community Siting Task Force, commissioned by TEC to locate a site for its future generating units.

The seventeen person group consisted of environmentalists, educators, economists, and community leaders. The study, which began in 1989, considered thirty-five sites in six counties. The Task Force recommended three tracts in southwestern Polk County that had been previously mined for phosphate. These sites had the best overall environmental and economic ratings. The selected site is about 4300 acres.

About one-third of the site will be used for the generating facilities (Figure 2). TEC will be responsible for development of the site. As part of this overall plan, the existing mine cuts will be modified and used to form an 850 acre cooling reservoir.

Another one-third of the site will be used for creating a complete ecosystem. It will include uplands, wetlands, and a wildlife corridor. This will provide a protected area for native plants and animals. The final one-third of the site will be unused, primarily used for site access and providing a visual buffer.

## THE PROJECT

Overview

The Polk Power Station Unit #1 IGCC Project will be constructed in two phases. TEC's operation needs called for 150MW of peaking capacity in mid-1995, becoming part of 260MW of baseload capacity in mid-1996. The first phase will be the installation of an advanced CT, scheduled for commercial operation in July 1995. This CT will fire No. 2 oil during its first year while in peaking service. During that year, TEC will complete installation of the gasification and combined cycle facilities which will be in commercial operation in July 1996. This phased approach will satisfy the generation expansion plan.

Part of this DOE CCT project will be to test and demonstrate a new hot gas clean-up (HGCU) technology. With the exception of the HGCU, only commercially available equipment will be used for this project. The approach supported by DOE is the highly integrated arrangement of these commercially available pieces of hardware or systems, in a new arrangement which is intended to optimize cycle performance, cost, and marketability at a commercially acceptable size of nominally 260MW (net). Use of the HGCU will provide additional system efficiencies by demonstrating the technical improvements realized from cleaning syngas at a temperature of about 1000°F rather than utilizing more traditional Cold Gas Clean-up (CGCU) methods: cooling the gas to about 100°F before the sulfur removal is attempted. This low temperature process has the disadvantage of the irreversible cooling losses and associated reheating before admitting the syngas to the CT.

Gasification

This unit will utilize commercially available gasification technology as provided by Texaco in their licensed oxygen-blown entrained-flow gasifier. A general flow diagram of the entire process is shown in Figure 3. In this arrangement, coal is ground to specification and slurried in water to the desired concentration (60-70% solids) in rod mills. The unit will be designed to utilize about 2300 tons per day of coal (dry basis). This coal slurry and an oxidant (95% pure oxygen) are then mixed in the gasifier burner where the coal partially combusts in an oxygen deficient environment, at a temperature in excess of 2500°F. This produces syngas with a heat content of about 250 BTU/SCF (LHV). The oxygen will be produced from an Air Separation Unit (ASU). The gasifier is expected to achieve greater than 95% carbon conversion in a single pass. It is currently planned for the gasifier to be a single vessel feeding into one radiant syngas cooler where the temperature will be reduced from about 2500°F to about 1300°F. After the radiant cooler, the gas will then be split into two (2) parallel convective coolers, where the temperature will be cooled further to about 900°F. One stream will go to the 50% capacity HGCU system and the other stream to the traditional CGCU system with 100% capacity. This flow arrangement was selected to provide assurance to TEC that the IGCC capacity would not be restricted due to the demonstration of the HGCU system.

The CGCU system will be a traditional amine scrubber type, with conventional sulfur recovery. Sulfur removed in the HGCU and CGCU systems will be recovered in the form of sulfuric acid and elemental sulfur respectively. Both of these products have a ready market in the phosphate industry in the central Florida area. It is expected that the annual production of 14,000 tons of elemental sulfur or 45,000 tons of sulfuric acid produced by this 260MW (net) IGCC unit will have minimal impact on the price and availability of these products in the phosphate industry.

Most of the ungasified coal exits the bottom of the gasifier/radiant syngas cooler into the slag lockhopper where it is mixed with water. These solids generally consist of slag and uncombusted coal products. As they exit the slag lockhopper, these non-leachable products are readily saleable for blasting grit, roofing tiles, and construction building products. TEC has been marketing slag from its existing units for such uses for over 25 years.

Obviously, the water in the slag lockhoppers requires treatment before it can be either discharged or reused. All of the water from the gasification process will be cleaned and reused, thereby creating no requirement for discharging process water from the gasification system.

Air Separation Unit

The Air Separation Unit (ASU) will use ambient air to produce oxygen for use in the gasification system and sulfur recovery unit, and nitrogen which will be sent to the advanced CT. The addition of nitrogen in the CT combustion chamber has dual benefits. First, since syngas has a substantially lower heating value than natural gas, a higher fuel mass flow is needed to maintain heat input. This additional mass flow has the advantage of producing higher CT power output. Second, the nitrogen acts to control potential $NO_x$ emissions by reducing the combustor flame temperature which, in turn, reduces the formation of thermal $NO_x$ in the fuel combustion process.

The ASU will be sized to produce about 2100 tons per day of 95% pure oxygen and 6300 tons per day of nitrogen. The ASU may be designed and constructed as a turnkey project.

HGCU

The HGCU system is being developed by General Electric Environmental Services, Inc (GEESI). This process is undergoing pilot plant testing at GE's laboratory facilities in Schenectady, NY. The advantage of the HGCU over the CGCU is the ability to use the syngas from the gasification system. Instead of having to cool the gas prior to sulfur removal, the HGCU will accept gas at 900-1000°F. The successful demonstration of this technology will provide for higher efficiency IGCC systems.

One specific issue in the HGCU system for our project is the metal oxide sorbent being demonstrated. The sorbent material used will be zinc titanate. This is a more robust material and more amenable to the oxygen-blown entrained-gasifier syngas than zinc ferrite, which is usually considered for air-blown gasifiers.

A regeneration system will produce a highly concentrated (about 13%) $SO_2$ stream. This will feed a sulfuric acid plant, for production of a saleable acid by-product.

The feasibility of two (2) other support processes will be investigated for potential improvements to this process. In addition to the high efficiency primary cyclone being provided upstream of the HGCU system, a high temperature barrier filter will be considered for possible installation downstream of the HGCU to protect the combustion turbine.

Use of sodium bicarbonate, $NaHCO_3$, will also be investigated for possible injection upstream of the barrier filter for removal of chloride and fluoride species on the barrier filter media by forming stable solids NaCl and NaF which would be disposed of with other plant solid byproduct streams.

Combined Cycle

The key components of the combined cycle are the advanced combustion turbine (CT), heat recovery steam generator (HRSG), steam turbine (ST), and generators.

GE is currently optimizing arrangements for increasing fuel inlet temperatures and also for lowering the pressure drop across the fuel inlet control valving. This has a compounding positive effect on cycle efficiency by also allowing a lower pressure in the ASU, requiring less air and nitrogen compressor parasitic power.

The HRSG is installed in the combustion turbine exhaust to complete the traditional combined cycle arrangement and provide steam to the 130MW steam turbine.

No auxiliary firing is proposed within the HRSG system. Hot exhaust from the CT will be channeled through the HRSG to recover the CT exhaust heat energy. The HRSG high pressure steam production will be augmented by high pressure steam production from the coal gasification (CG) plant. All high pressure steam will be superheated in the HRSG before delivery to the high pressure ST.

The ST will be designed as a double flow reheat turbine with low pressure crossover extraction. The ST generator will be designed specifically for highly efficient combined cycle operation with nominal turbine inlet throttle steam conditions of approximately 1,450 psig and 1,000°F with 1,000°F reheat inlet temperature.

The operation of the combined cycle power plant will be coordinated and integrated with the operation of the CG process plant. The initial start-up of the power plant will be carried out on low-sulfur No. 2 fuel oil. Transfer to syngas will occur upon establishment of fuel production from the CG plant.

Under normal operation, syngas and nitrogen from the ASU will be provided to the CT. The syngas/nitrogen mix at the CT combustion chamber will be regulated by the CT control system to control the $NO_x$ emission levels from the unit.

Cold reheat steam from the high pressure turbine exhaust and HRSG intermediate pressure steam will be combined before reheating in the HRSG and subsequent admission to the intermediate pressure ST. Some intermediate pressure steam will also be supplied from the HRSG to the sulfur recovery unit.

Integration

The heart of the overall project will be the integration of the various pieces of hardware and systems. Maximum usage of heat and process flow streams can usually increase overall cycle effectiveness and efficiency. In our arrangement, benefits are derived from using the experience of other IGCC projects, such as Cool Water, to optimize the flows from different subsystems. For example, low pressure steam from the HRSG will be produced to supply heat to the CG facilities for process use. The HRSG will also receive steam energy from the CG syngas coolers to supplement the steam cycle power output. Additional low energy integration will occur between the HRSG and the CG plant. Low pressure steam will be provided by the HRSG to the CG facilities for process use. Some low level waste heat in the CG facilities will be used for condensate heating for the HRSG. Condensate from the ST condenser will be returned to the HRSG/integral dearator by way of the gasifier, where some condensate preheating occurs.

Probably the most novel integration concept in this project is our intended use of the ASU. This system provides oxygen to the gasifier in the traditional arrangement, while simultaneously using what is traditionally excess or wasted nitrogen to increase power output and improve cycle efficiency and also lower $NO_x$ formation.

Emissions

The primary source of emissions from the IGCC unit is combustion of syngas in the advanced CT (GE 7F). The exhaust gas from the CT will be emitted to the atmosphere via the HRSG stack. Emissions from the HRSG stack are primarily $NO_x$ and $SO_2$ with lesser quantities of CO, VOC, particulate matter (PM). Table 1 presents the estimated maximum hourly emission rates for this source. The emission control capabilities of the HGCU system are yet to be fully demonstrated. Therefore, some emission estimates are higher compared to estimated emissions from the CGCU system. After the completion of the 2-year demonstration period, the lower emission rates from the CGCU system must be achieved to meet permit requirements.

It is expected that at least 96 percent of the sulfur present in the coal will be removed by the CGCU and HGCU systems.

The advanced CT in the IGCC unit will use nitrogen addition to control $NO_x$ emissions during syngas firing. Nitrogen acts as a diluent to lower peak flame temperatures and reduce $NO_x$ formation without the water consumption and treatment/disposal requirements associated with water or steam injection $NO_x$ control methods. Maximum nitrogen diluent will be injected to minimize $NO_x$ exhaust concentrations consistent with safe and stable operation of the CT. Water injection will be employed to control $NO_x$ emissions when backup distillate fuel oil is used and during the first year of the 7F CT operation when the unit is operated in the simple cycle mode.

## DEMONSTRATION

Part of the Cooperative Agreement for this project is the two-year demonstration phase. During this period it is planned that about four to six different types of coals will be tested in the operating IGCC power plant. The results of these tests will compare this unit's efficiency, operability, and costs, and report on each of these test coals specified against the design basis coal. These results should provide a menu of operating parameters and costs which can be used by utilities in the future as they make their selection on methods for satisfying their generation needs, in compliance with environmental regulations.

## SCHEDULE

Table 2 presents key project milestones. To date, Letters of Intent have been signed with Texaco Development Corporation for the gasification license, GE for the combined cycle system, and GEESI for the HGCU system. Finalization of contracts is expected shortly.

During the next fifteen months, preliminary engineering and the final process arrangements will be complete. National Environmental Policy Act (NEPA) activities are expected to be finalized by year end 1993, allowing for the start of construction at the beginning of 1994.

This will lead to the commercial operation of the CT in July 1995 and the IGCC unit in July 1996. Following the demonstration period, TEC expects to operate the 260MW (net) unit in baseload operation producing low cost, coal-based, reliable power.

# Polk Power Station

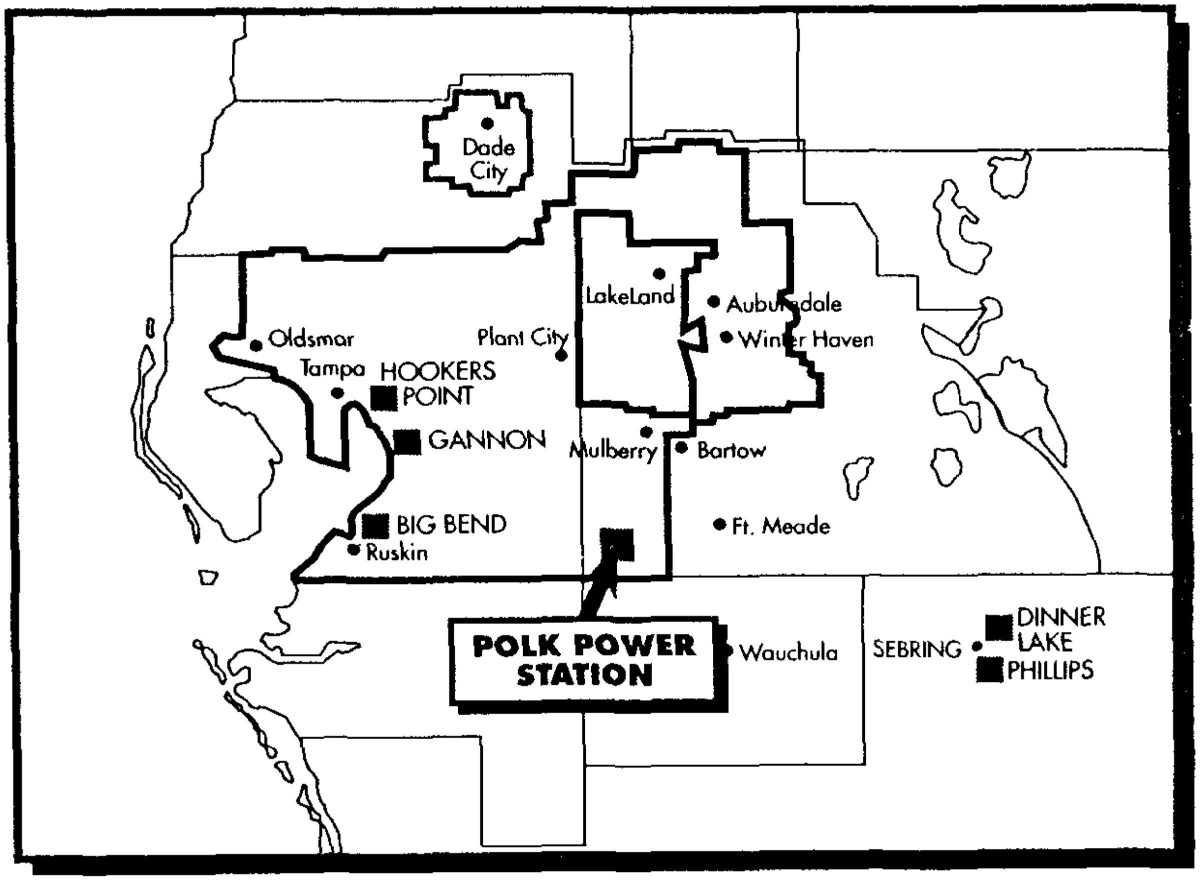


Figure 1. Location of Polk Power Station

# Polk Station Site

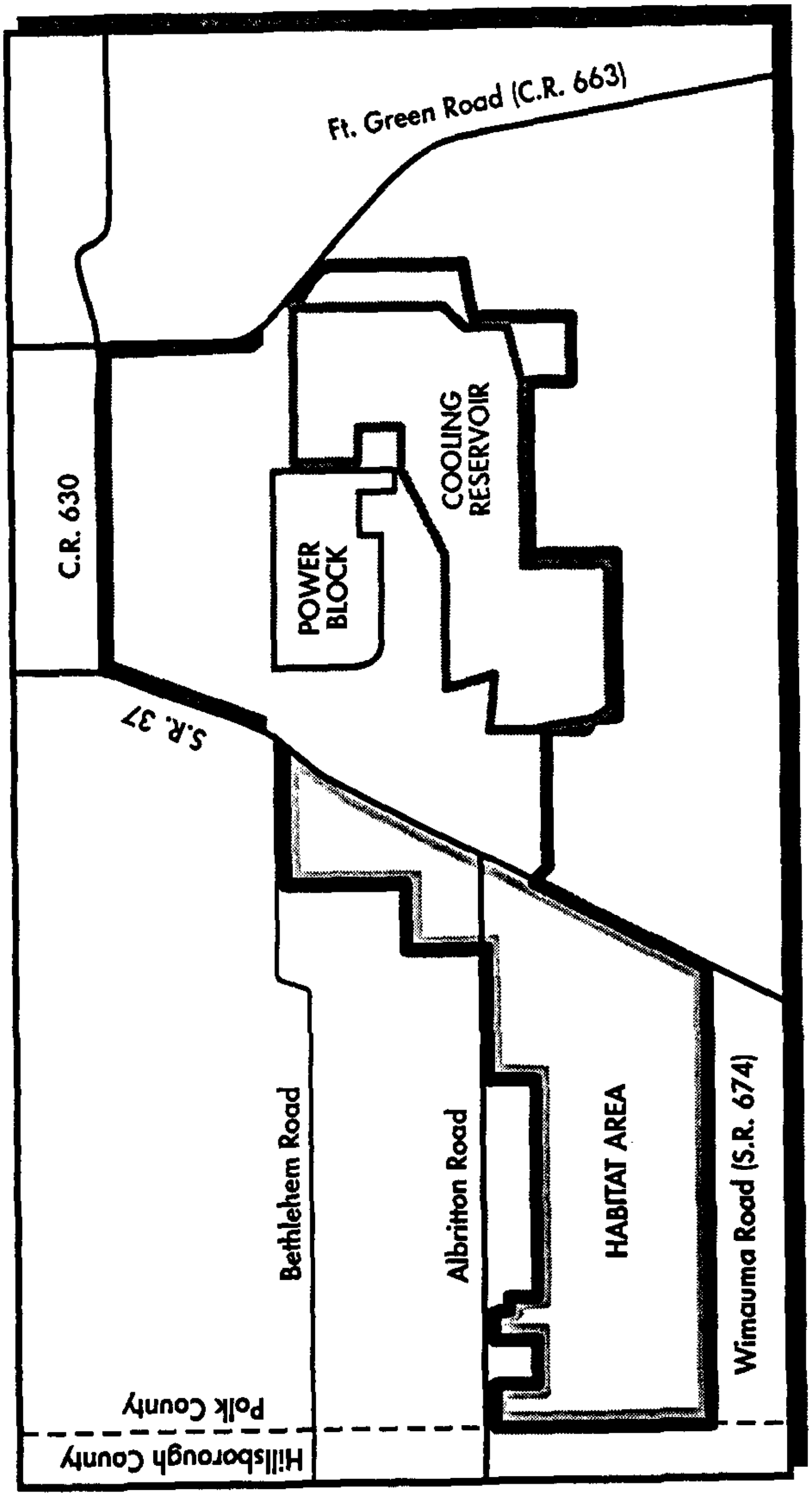


Figure 2. Polk Power Station Site Layout

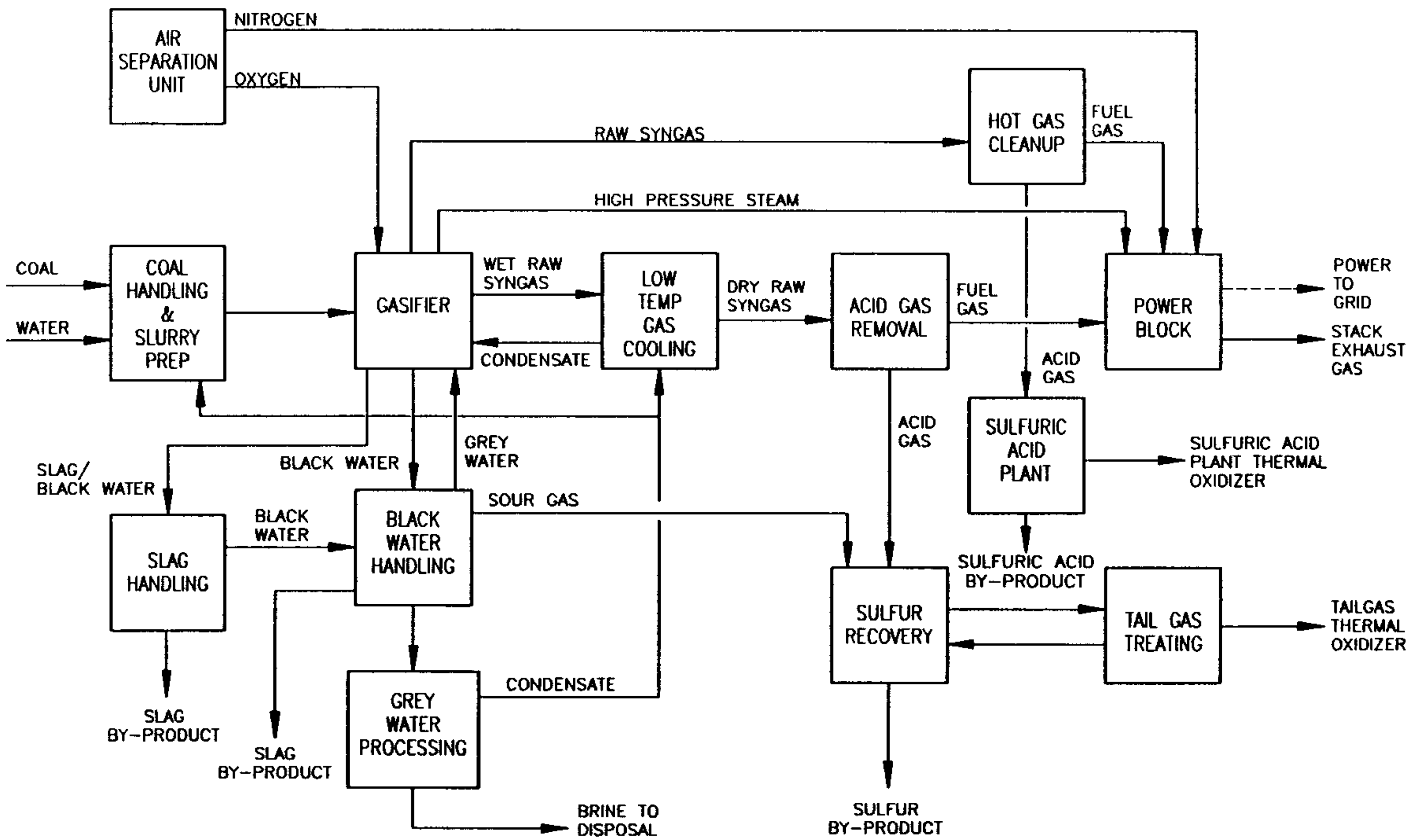


Figure 3. Generalized Flow Diagram of IGCC System

| Constituent | Post-Demonstration* | Demonstration† | No.2 Fuel Oil |
|---|---|---|---|
| Particulate Matter | 72 | 72 | 27 |
| $SO_2$ | 518 | 518 | 92 |
| $NO_x$ | 223 | 664 | 311 |
| CO | 98 | 99 | 99 |
| VOC | 3 | 3 | 32 |

* Maximum emissions after the 2-year demonstration period, based on emissions achievable with CGCU. Utilization of HGCU to be based on ability to achieve maximum post-demonstration emission rates.

† Maximum emissions during the 2-year demonstration period, based on up to 50 percent utilization of HGCU. Maximum post-demonstration emission rates to be achieved thereafter.

**Table 1. Maximum Emissions from the IGCC Unit's CT (All Values lb/hr)**

| Date | Activity |
|---|---|
| January 1992 | Need for Power Certification received from State of Florida |
| February 1992 | Texaco, Inc. awarded contract for preliminary engineering/process development |
| March 1992 | Novated Cooperative Agreement signed |
| April 1992 | Volume of Environmental Information submitted to DOE |
| April 1992 | Letters of Intent initiated with Texaco and General Electric |
| July 1992 | Site Certification Application submitted to Florida Department of Environmental Regulation |
| August 1992 | DOE Scoping Meeting |
| September 1992 | Request bids for detailed engineering |
| May 1993 | Certification hearing before State of Florida |
| Fall 1993 | Receive permits |
| January 1994 | Start construction |
| July 1995 | Commercial operation of CT |
| July 1996 | Commercial operation of IGCC |

**Table 2. Major Project Milestones**

# SESSION 2:
# High Performance Pollution Control Systems

*Chairs: Dr. Joseph P. Strakey, DOE PETC*
*Dr. Lawrence Saroff, DOE Headquarters*

**Acid Rain Compliance — Advanced Co-Current Wet FGD Design for the Bailly Station,** Robert C. Reighard, Director of Operations, Pure Air. Authors: Beth Wrobel, Northern Indiana Public Service Company, and Don C. Vymazal, Pure Air

**Demonstration of Innovative Applications of Technology for the CT-121 FGD Process**, David P. Burford, Project Manager, Southern Company Services, Inc. Co-authors: Harry J. Ritz, DOE Pittsburgh Energy Technology Center, and Oliver W. Hargrove, Radian Corporation.

**$NO_x/SO_2$ Removal With No Waste — The SNOX Process**, Timothy D. Cassell, SNOX Site Leader, ABB Environmental Systems. Co-authors: Sher M. Durrani, Project Manager, Ohio Edison Company, and Robert J. Evans, Project Manager, U.S. DOE Pittsburgh Energy Technology Center.

**SNRB - $SO_2$, $NO_x$, and Particulate Emissions Control with High Temperature Baghouse**, Kevin E. Redinger, Project Manager, The Babcock & Wilcox Company. Co-authors: Rita E. Bolli, Ohio Edison Company, Ronald W. Corbett, U.S. DOE Pittsburgh Energy Technology Center, and Howard J. Johnson, Ohio Coal Development Office.

**The NOXSO Clean Coal Technology Project: A 115 MW Demonstration Unit,** Dr. James B. Black, Sr. Project Engineer, NOXSO Corporation. Co-authors: L.G. Neal, John L. Haslbeck, and Mark C. Woods, NOXSO Corporation

**Overview of the Milliken Station Clean Coal Demonstration Project,** Mark E. Mahlmeister, Project Engineer, New York State Electric & Gas Corporation. Co-authors: J.E. Hofman, NALCO Fuel Tech, R.M. Statnick, CONSOL, Inc., C.E. Jackson, Gilbert Commonwealth, Gerard G. Elia, U.S. DOE Pittsburgh Energy Technology Center, J. Glamser, S-H-U/Natec, and R.E. Aliasso, Stebbins Engineering & Manufacturing Co.

# ACID RAIN COMPLIANCE - ADVANCED CO-CURRENT WET FGD DESIGN FOR THE BAILLY STATION

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## ABSTRACT

Northern Indiana Public Service Company (NIPSCO) has chosen an unique approach to comply with air quality regulations at its Bailly Generating Station. The utility has entered into a 20-year agreement with Pure Air to design, engineer, construct, fabricate, own, operate, maintain and finance the FGD project. Pure Air, a general partnership company between Air Products and Chemicals, Inc. and Mitsubishi Heavy Industries America, Inc., was selected by the U.S. Department of Energy (DOE) under the Clean Coal Technology Program to install an advanced co-current, wet flue gas desulfurization (FGD) system at the Bailly Generating Station. The project combines the most advanced features of Mitsubishi's 87 units worldwide (over 24,000 MW installed) and an innovative commercial arrangement into a single project to demonstrate substantially lower capital and operation costs when compared to conventional FGD designs. This paper discusses advanced wet FGD design features, the own and operate commercial arrangement, the costs of the Bailly project, and project status.

## BACKGROUND

Pure Air, a general partnership between Air Products and Chemicals, Inc. (Air Products) and Mitsubishi Heavy Industries America, Inc. (MHIA), was established in 1985 to market flue gas desulfurization (FGD) equipment and services in North America. MHIA is a wholly-owned subsidiary of Mitsubishi Heavy Industries, Ltd. which has sold 87 FGD units worldwide, with a total of over 500 years of operating time on all the units combined (Table 1). The joint venture combines Mitsubishi's Advanced FGD technology with Air Products' plant construction and operations capability to form a company which can either sell the FGD equipment or design, construct, finance, own, operate, and maintain FGD plants. Air Products pioneered the "On-Site" concept over 40 years ago, and currently owns and operates over 165 industrial gas, chemical, cogeneration, and waste-to-energy plants around the world. Many of the same types of economic benefits successfully demonstrated in other industries with own and operate project services provided by an experienced chemical plant operator can be transferred to the FGD market.

Pure Air began development efforts in early 1988 for an On-Site Advanced FGD facility serving the Northern Indiana Public Service Company (Northern Indiana). With the cooperation of Northern Indiana, the project was submitted to the United States Department of Energy (DOE) for consideration under the Innovative Clean Coal Technology Program (Solicitation II), and was selected in September 1988 to receive cooperative funding of $63,434,000.

In September 1989, a flue gas processing agreement was signed with Northern Indiana, whereby, an Advanced FGD facility will be constructed at its Bailly Generating Station in Dune Acres, Porter County, Indiana (on the southern shore of Lake Michigan adjacent to the National Lakeshore). The facility will provide flue gas processing services for Bailly Units #7 and #8 which together have a nameplate capacity of approximately 600 megawatts.

The primary purpose of the Bailly project is to demonstrate that by combining Advanced FGD technology, highly efficient and sophisticated plant operation and maintenance capabilities, and by-product gypsum sales, significant quantities of sulfur dioxide emissions reduction can be achieved at a substantially lower cost than currently available FGD systems. The Bailly Project will use the following advanced features which will have economic effects on future FGD systems:

- Single 600 MW module which will reduce costs for power plants over 200 MW. Use of a single 100% capacity absorber module will demonstrate that spare modules are no longer necessary due to the high reliability of the module design.
- Co-current, single loop absorber with in-situ oxidation producing high quality gypsum while operating with a wide range of high sulfur coals. Oxidation will be accomplished by an innovative air rotary sparger system.
- The FGD supplier will own and operate the plant for 20 years or more and provide ongoing performance guarantees which will reduce operating risk and cost to utilities and their customers.
- Sale of commercial grade gypsum to a wallboard manufacturer.
- Direct injection of powdered limestone.
- High sulfur dioxide removal efficiency up to 95%.
- Wastewater Evaporation System (WES) which will reduce water disposal problems inherent with many U.S. power plants.
- Multiple boilers to a single absorber module which will significantly reduce costs at power plants with multiple boiler units.

## ADVANCED FGD PROCESS OVERVIEW

A schematic of the Advanced FGD system process flow for co-current, single loop/in-situ oxidation is depicted in Figure 1. The following discussions present a process description of the various sections of the process with reference points noted on the process flow diagram.

### System Chemistry and Operation

The Advanced FGD system that Pure Air and Northern Indiana will demonstrate will be a blend of innovative and existing process technologies. The Advanced FGD system will be the first demonstration of various process features on high sulfur coal, and the Advanced FGD will integrate all of these features into a single 600 MW scrubbing system.

1. **Sulfur Dioxide Absorption Section**

The flue gas flows through a co-current open grid packed tower. Constantly recycled slurry is used to quench the hot gas and to provide available alkali for the collection of sulfur dioxide in the grid stage. The intimate contact between the slurry and the flue gas in the grid stage also enhances natural oxidation. The following reactions occur:

**ABSORBER**

$SO_2 + O_2 ===> H_2SO_3$
$H_2SO_3 ===> H^+ + HSO_3-$
$(H+ HSO_3- + 1/2\ O_2 ===> 2H^+ + SO_4^{-2})$ Natural Oxidation
$(2H^+ + SO_4^{-2} + CqCO_3 + Aq ===> CaSO_4 \bullet 2H_2O + CO_2)$

The integral absorber tank is utilized as the recycle reservoir, the in-situ oxidation vessel, and the reaction tank for limestone dissolution. A blower is used to introduce air into the integral tank to effective over 99% oxidation of sulfite to sulfate. Gypsum slurry is drawn from the integral tank to maintain a 20-25 weight percent slurry content. This stream is collected in a surge tank for further processing.

**INTEGRAL SUMP/OXIDATION VESSEL**

$H^+ + HSO_3^- + 1/2\ O_2 ===> 2H^+ + SO_4^{-2}$ Forced Oxidation
$2H^+ + SO_4^{-2} + CaCO_3 + Aq ===> CaSO_4 \bullet 2\ H_2O + CO_2$

As the gas/slurry mixture exits the grid stage and changes flow direction, gravity separates the two phases. Slurry falls to the absorber tank while the flue gas passes through a multi-stage mist eliminator that is washed intermittently. Collected entrainment is returned to the absorber, while clean gas flows to the stack. Dry powdered limestone is pneumatically conveyed from pulverized limestone silos and injected directly into the absorber tank. Make-up water is reclaimed from the Gypsum Dewatering Section.

2. Gypsum Dewatering Section

Raw gypsum slurry is batch fed into automatically programmed basket type centrifuges with washing systems. The final product contains 6-8 weight percent moisture (10% maximum).

Filtrate water reclaimed from the raw gypsum is not disposed. A blowdown stream is used to maintain contaminant levels (Cl-, Al+++, Mg++, etc.) within system limits. The remainder is recycled to the absorber for evaporative losses.

3. Wastewater Evaporation System (WES)

Under Normal operating conditions the blowdown wastewater is injected into the duct work upstream of the Unit #8 electrostatic precipitator. A back-up WWTS has been installed to handle any water not processed in the WES. Under certain operating conditions, wastewater in excess of that which will be processed in the WES will be treated in Pure Air's water treatment system.

## Facilities Description

The Advanced FGD system installed on Bailly Unit #7 and Unit #8 has been designed from a long term operating viewpoint. Since the anticipated useful life of the power plant is 20 years, Pure Air must strive for maximum reliability and component life. The use of spare parts, future expansion capability and top quality materials of construction ensures project continuity through its initial 20-year life. Further, at the end of 20 years, Northern Indiana will have the option to continue to extend the agreement with Pure Air and the facility's use for many years.

1. Sulfur Dioxide Absorption Section

Flue gas is collected from both Bailly Unit #7 and Unit #8 and ducted to a single co-current absorber. This gas flow configuration allows a higher superficial velocity (2 to 3 times that of a counter-current vessel). By using high-efficiency open grid packing, tower height is also reduced. This, combined with the use of dry powdered limestone, minimizes the land area required at the flue gas source.

Rubber lined pumps are used exclusively in slurry service, including the absorber recirculation and absorber bleed pumps. Forced oxidation and tank agitation are accomplished by use of a corrosion-resistant Air Rotary Sparger (ARS). The ARS reduces air and power requirements from those of fixed sparger designs. A small fixed air sparger is also installed in the absorber tank. A high efficiency, vertical two-stage chevron-type mist eliminator, made of thermoplastic, is employed in the horizontal gas flow to virtually eliminate droplet carryover.

In order to protect the lining of the absorber shell from being exposed to extremely high temperature conditions which would be caused by absorber recirculating system malfunction, an emergency quenching system is provided. This system is comprised of a quench water pump and emergency spray nozzles which are installed in the absorber.

The entire instrumentation system will be monitored, controlled and alarmed by an integrated distributed digital control system. Since the Advanced FGD design does not employ multiple absorber towers, no flue gas balancing is required. Sulfur dioxide removal efficiency is controlled by a combined feed forward/feed back system. Removal efficiency is directly related to the outlet sulfur dioxide concentration. The outlet sulfur dioxide monitor detects any variation in signal caused by a change in FGD inlet sulfur dioxide load, and the control system adjusts the limestone feed quantity to compensate. The limestone addition rate is further trimmed by a feed forward signal of boiler load. This system will then maintain removal efficiency over a wide variety of boiler loads and coal sulfur contents.

## 2. Gypsum Dewatering Section

The centrifuge feed pumps deliver raw gypsum slurry, based upon slurry density in the absorber sump, directly to the feed manifold for the centrifuges. There are three major stages in a centrifuge batch sequence; (1) start-up and raw gypsum charge, (2) dewatering and cake washing, and (3) shutdown discharge and cleaning. With each of the centrifuges in a different stage, raw gypsum feed and by-product gypsum production appear to be continuous operations. By-product gypsum will be conveyed to a storage facility for transport to a wallboard manufacturer.

## 3. Wastewater Evaporation System

Filtrate reclaimed from the centrifuges is collected in a filtrate sump. The sump and agitator are corrosion/erosion resistant, and the filtrate sump is fitted with vertical sump pumps which feed reclaimed water to the thickener where entrained solids are separated. The majority of the filtrate water is recycled back to the absorber.

Part of the filtrate water from the thickener over flow tank is pumped, on a flow control basis, to a grid of spray nozzles located in the duct work upstream of the Unit #8 ESP. The flash dried material is collected simultaneously with the fly ash.

4. **Limestone Handling and Transfer System**

Powdered limestone will be delivered to the site in 24 ton trucks. Unloading blowers move the limestone from the trucks to storage silos. Each silo will have a single discharge, a limestone feeder, and a transport jet conveyor. Transfer blowers will deliver limestone to the absorber through a pneumatic conveying system.

## DEMONSTRATION PROGRAM EXECUTION

Pure Air will conduct a 68-month program of engineering, procurement, construction, start-up, and operation of the Advanced FGD processing facility. The overall program will confirm the technical reliability and cost effectiveness of the Advanced FGD design.

### Demonstration Test Plan

After the start-up of the Advanced FGD system, a series of tests will be performed by Pure Air and Northern Indiana over a period of three years to demonstrate the operation of the facility using a wide range of coal feeds. Five of the demonstration runs will last a total of 20 weeks and will test coals of specific sulfur content which are available in the Indiana/Illinois region:

- between 2.0 and 2.5 weight percent sulfur
- between 2.5 and 3.0 weight percent sulfur
- between 3.0 and 3.5 weight percent sulfur
- between 3.5 and 4.0 weight percent sulfur
- between 4.0 and 4.5 weight percent sulfur

The tests which are anticipated to be performed for each of these periods are summarized in Table 2. The overall objective for all four test periods is the measurement of sulfur dioxide removal efficiency of the Advanced FGD design and the confirmation of the gypsum by-product quality while burning various coals. Since the demonstration plant is serving an existing active power plant, operation at varying loads will demonstrate turndown and cycling operation capabilities of the Advanced FGD design.

The last test at the maximum design sulfur content in the coal (between 4.0 and 4.5 weight percent) and at maximum boiler load conditions will also be performed. This test will demonstrate the operation of the Advanced FGD facility at sulfur dioxide removal efficiencies up to 95 percent while simultaneously producing wallboard-quality gypsum.

A sixth test, also lasting about one month, will be performed near the end of the three-year demonstration period using an optimum coal supply for the Bailly generating station. Analysis of the data from the earlier test periods described above will provide a unique opportunity during this operation. The primary objective of this final test is to determine the lowest unit cost for the most efficient $SO_2$ removal, while firing the optimum coal (or combination of coals) and producing the highest quality salable gypsum.

In addition to those tests listed in Table 2 which are specific to particular coal sulfur contents and boiler loads, other tests of specific equipment items and operating parameters are also planned over the three-year demonstration period. As indicated in Table 3, these tests include a reliability and maintenance study of the major equipment items used in the Advanced FGD system.

As described in the demonstration plan, the Advanced FGD design will be thoroughly evaluated. The flue gas stream composition will be changed by utilizing different coals during the demonstration period. Power plant operations will be varied to test the turndown ratio of the Advanced FGD design, its response to upset conditions and its ability to respond to rapid increases in flue gas flow rates. (Further, the effect of changing limestone fineness on Advanced FGD operations will be tested.) Each of these tests will serve to maximize advancement of the Advanced FGD technology.

## COMMERCIAL ARRANGEMENT

Northern Indiana has signed a flue gas processing agreement with Pure Air, whose scope includes the following: design, engineer, fabricate, construct, finance, own, operate and maintain an Advanced FGD facility adjacent to the Bailly generating station. Under this agreement, Pure Air is responsible for (i) procurement of limestone, (ii) processing and returning of flue gas, and (iii) delivery of wallboard grade gypsum to Northern Indiana, (iv) treatment of the wastewater from the AFGD facility. Pure Air also assisted in the development of a gypsum sales contract as part of its services to Northern Indiana on this project.

Northern Indiana will pay a monthly Base Facility Charge (BFC) for flue gas processing services. The BFC was essentially fixed at contract execution, almost three years before commercial operation. The BFC is comprised of the following components:

- Fixed Component - Fixed for 20 years (Capital recovery, financing costs, start-up cost, spare parts, and risk premium).
- Fixed Variable Component - Escalates with indices (Base operating and maintenance cost recovery).
- Limestone Component - Escalates with indices (Utilization guarantee).

The Fixed Component is constant over the life of the agreement. It should be noted that this price was determined at contract execution and any cost overruns due to Pure Air's estimate are to Pure Air's account, thus providing a fixed lump sum capital cost contract.

The Fixed Variable and Limestone Components were determined at contract execution and are subject to adjustment on a quarterly basis. The Limestone Component will be adjusted for the sulfur content of the coal and plant capacity factor. The Fixed Variable Component provides Northern Indiana with fixed base operating and maintenance cost for the term of the agreement, thus providing a long-term fixed operating contract to Northern Indiana. This approach makes Pure Air responsible for the turnkey, financing, operating and maintenance risks as well as the FGD system performance.

After completion of the demonstration period, Northern Indiana will enter into a long-term commercial agreement with Pure Air to process their flue gas generated from the Bailly Station. Pure Air will guarantee the following items:

- Sulfur Dioxide Removal Efficiency
- Reliability
- Gypsum Quality (purity and moisture content)
- Capital Cost of the Advanced FGD Facility (at execution of the agreement)
- Base Operating and Maintenance Costs (at execution of the agreement and for the term of the agreement).
- Power Consumption
- Pressure Drop
- Process Water Usage
- Wastewater Quality

Over the last five years, U.S. utilities have recognized the viability of worldwide FGD trends previously not accepted in the U.S. Pure Air is presently marketing this Advanced FGD process to utility and industrial customers. This Pure Air Advanced FGD system incorporates virtually all of the features recommended in the Advanced FGD philosophy the Electric Power Research Institute which recommended to the utility marketplace(1) at the First Combined FGD and Dry $SO_2$ Removal Symposium in St. Louis in October, 1988.

## BAILLY PROGRAM COST OVERVIEW

The total program cost for this project is approximately $150.5 million. This program cost includes Advanced FGD capital costs, Northern Indiana's capital costs, power costs, land costs, environmental permits, fuel costs for Northern Indiana, and project operating costs for the first three years of operation. These costs can be broken down as follows:

| Description | Components ($MM), 1992$ | Totals ($MM), 1992$ |
|---|---|---|
| Absorber, Ducting and Associated Equipment | $55.5 | |
| Gypsum Dewatering and Handling | 15.9 | |
| Limestone Handling and Storage | 2.3 | |
| Subtotal - Advanced FGD Costs | | $73.7 |
| Start-up and Spare Parts | 6.1 | |
| Power Plant Modifications (Northern Indian Capital) - New Stack, Relocation of Buildings, AFUDC | 23.9 | |
| Short-Term Interest | 6.0 | |
| Subtotal - Other | | 36.0 |
| Demonstration Period Operating Costs | | 40.8 |
| Total Program Costs | | $150.5 |

DOE cooperative funding supports approximately 42% of the program costs for a total of $63.4 MM. The DOE funding is applied to capital costs and operating costs during the Demonstration Period (the first three years of operation).

## BAILLY PROJECT ISSUES

Some Bailly Project issues required the extensive team effort of both Pure Air and Northern Indiana to resolve. These included the Indiana Utility Regulatory Commission (IURC). Approval Permits, and Gypsum Sales. The following is a short description of the issues and their handling of these issues:

### Indiana Utility Regulatory Commission Approval

Indiana Senate Bill 505 became effective on July 1, 1989. This bill requires an Indiana Utility Regulatory Commission review before a public utility may implement a clean coal technology. The formal approval is titled "Certificate of Public Convenience and Necessity." Northern Indiana was required to obtain this certificate and thus this approval by the IURC forecloses subsequent challenges to the inclusion of the technology in the rate base on the basis of excessive cost, adequate quality control, or inability to employ the technology.

The IURC was required by this bill to examine the following factors when determining whether to grant the certificate:

1. The costs for constructing, implementing, and using clean coal technology compared to the costs for conventional emission reduction facilities.

2. Whether a clean coal technology project will also extend the useful life of an existing generating facility and the value of that extension.

3. The potential reduction of sulfur and nitrogen based pollutants achieved by the proposed clean coal technology system.

4. The reduction of sulfur and nitrogen based pollutants that can be achieved by conventional pollution control equipment.

5. Federal sulfur and nitrogen based pollutant emission standards.

6. The likelihood of success of the proposed project.

7. The cost and feasibility of retiring the existing electric generating facility.

8. The dispatching priority for the facility utilizing clean coal technology, considering direct fuel costs, revenues and expenses of the utility, and environmental factors associated with by-products resulting from the utilization of the clean coal technology.

9. Any other factors the commission considers relevant, including whether the construction, implementation, and use of clean coal technology is in the public's interest.

In addition--first and foremost, Northern Indiana had to prove that the Pure Air technology was not in commercial use in the United States as of January 1, 1989.

A procedural schedule was developed that established specific dates for all involved parties to submit testimony and attend hearings. The original schedule encompassed the time frame from August 27, 1989, until March 1, 1990. Due to an agreement between the interveners, the IURC, and Northern Indiana, the schedule was shortened to conclude on January 11, 1990. On April 11, 1990, Northern Indiana received a Certificate of Public Convenience and Necessity from the IURC.

One of the stipulations of the Certificate was an annual review and update on the anniversary of the Certificate. This review was to update the IURC on any cost changes "or anything else the Commission deemed necessary." In early 1991, Northern Indiana started the process of the annual review. This review specifically addressed the issues of accounting treatment of certain deferred cost approval of the revised estimate of costs and the transfer of the wastewater treatment system from Northern Indiana's scope of supply to Pure Air's scope of supply.

## Permits

The project was faced with obtaining typical environmental permits/approvals for construction and operation including those for air emissions, wastewater discharges, and waste disposal. In addition because the project involves the Department of Energy funds, an Environmental Assessment (EA) was involved.

Air quality impact issues were addressed through the Indiana Department of Environment Management's (IDEM) Office of Air Management (OAM). Since the Bailly Station will have two (2) stacks, an existing and AFGD stack, each will have a different emission limits. The existing stack will have a $SO_2$ limit of 6.0 lb/MMBtu while the new stack will have a 1.2 lb/MMBtu limit.

A fugitive dust plan was developed as part of the Permit to Construct application. Due to the handling of products such as limestone, lime, and gypsum, there was a concern that fugitive dust would occur due to vehicle resuspension. A road washing program was proposed and accepted by IDEM, OAM which alleviated that concern.

The permit stipulated the following:

- $SO_2$ emissions limit of 1.2 lb/MMBtu;
- particulate matter emissions limit of 0.22 lb/MMBtu;

- visible emissions limit of 40 percent opacity;
- continuous emission monitoring (CEM) of $SO_2$ before and after the absorber vessel;
- CEM for percent oxygen or carbon dioxide;
- CEMs for recording of opacity before absorber in individual ducts from Units 7 and 8;
- sulfur content of coal used at the Station shall not exceed 4.5 percent;
- bunkered coal will be sampled on a daily basis for heat content and percent sulfur; and,
- stack tests for $SO_2$ and particulate matter shall be required for a schedule specified in the permit.

Since the AFGD System, wastewater will be combined with the existing Bailly Station's Wastewater, IDEM, Office of Water Management (OWM) concluded that the Station's National Pollutant Discharge Elimination System (NPDES) permit should be modified.

The AFGD produces two (2) wastewater streams: domestic sanitary sewer wastes and process wastewater from the AFGD. The final permit limits are as follows:

## REFERENCES


1. "Advanced Simplified FGD Design", Dalton, Stuart M., Moser, Robert E., Electric Power Research Institute, and Burke, Jack M., Colley, J. David, Radian Corporation, October 1988.

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3. "Permitting and solid waste management issues for the Bailly Station Wet Limestone AFGD System", Bolinsky F.T., Pure Air, Ross, J. NIPSCO, Dennis D.S., United Engineer and Constructors, Huston, J.S. Environmental Alternatives, Inc. IGCI

4. Approval process to receive executive and IURC approval for an advanced FGD system; Sweet, B.K. NIPSCO, December 1990.

# TABLE 1

# PURE AIR PROCESS DELIVERY RECORD

| COUNTRY | ABSORBENT | FUEL | NO. OF UNITS | TOTAL MWS |
|---|---|---|---|---|
| **Utility Use:** | | | | |
| China | Limestone | Coal | 2 | 720 |
| Denmark | Limestone | Coal | 2 | 500 |
| Germany | Lime | Coal | 5 | 1021 |
| Germany | Limestone | Coal | 14 | 3170 |
| Japan | Limestone | Coal | 20 | 9438 |
| Japan | Lime | Oil | 10 | 2130 |
| Japan | Limestone | Oil | 17 | 4354 |
| United States | Limestone | Coal | 3 | 1580 |
| | | TOTALS | 73 | 22,913 |
| **Industrial Use:** | | | 14 | 1,478 equiv* |
| | | GRAND TOTAL | 87 | 24,391 |

*Flue Gas Volume 4,956,7000 NM³/H

# TABLE 2

## BREAKDOWN OF TESTS DURING DEMONSTRATION TESTS

| | |
|---|---|
| 1-5 - Limestone Feed Rate | Vary stoichiometric ratio up to limit on gypsum purity |
| 6-35 - Liquid/Gas Ratio | Run up to three liquid rates for boiler loads from minimum on Unit 7 (around 10% of overall station output) to 100% at intervals of 10% |
| 36-53 - Air Flow to ARS | At boiler loads of 20, 30, 50, 70, 90, and 100%, run up to three air flows to determine the minimum air flow while maintaining gypsum purity |

**Notes:**

For the Liquid/Gas Ratio at 100% load, design conditions for both limestone stoichiometry and air flow to the ARS will be used.

# TABLE 3

# TESTS PERFORMED OVER 3-YEAR DEMONSTRATION PERIOD

RAM (Reliability/Availability/Maintainability) Analysis
- used to verify mechanical performance of equipment items, develop maintenance schedule and equipment life

Change in Limestone Particle Size and Limestone Source

Waste Evaporation System (WES) (approximately 30 tests)
- study the effects of water flow and flue gas temperature on performance of WES and downstream electrostatic precipitator (ESP)

Optimization of Basket Centrifuge Operation (approximately 50 tests)
- determine the effects of wash water and centrifuge operating parameters on gypsum purity

Response of Advanced FGD system to trip of at least one boiler

Response of Advanced FGD system during start-up of one or both boilers

Test of advanced FGD Emergency Quenching System
- Simulation of air heater trip

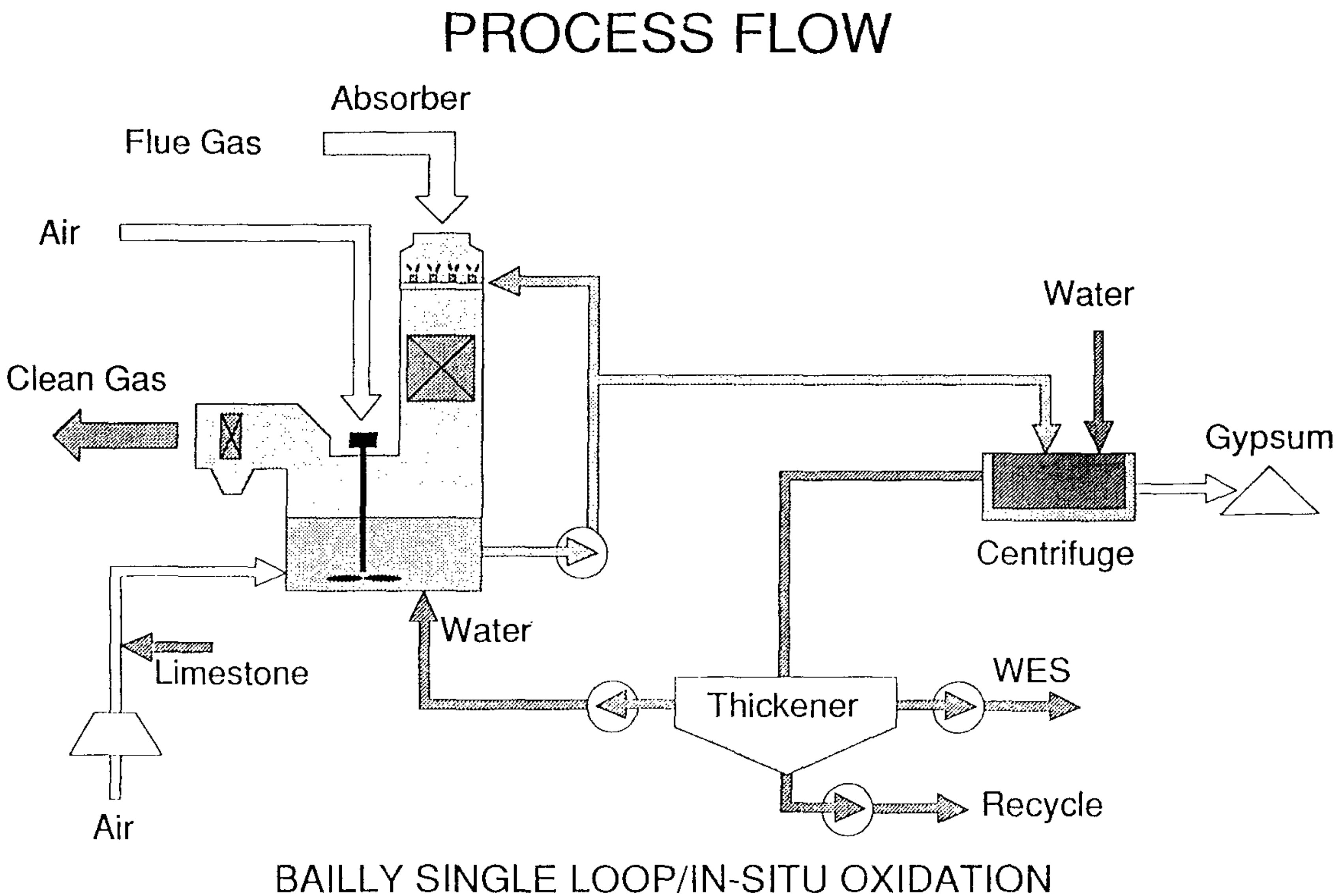
PROCESS FLOW
Absorber
Flue Gas
Air
Water
Clean Gas
Gypsum
Centrifuge
Water
Limestone
WES
Thickener
Recycle
Air
BAILLY SINGLE LOOP/IN-SITU OXIDATION
5302F1

FIGURE 1.

# DEMONSTRATION OF INNOVATIVE APPLICATIONS OF TECHNOLOGY FOR THE CT-121 FGD PROCESS

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## ABSTRACT

The Chiyoda Clean Coal Project at Georgia Power's Plant Yates Unit 1 is a $36 million project cofunded by the Department of Energy, the Electric Power Research Institute, and The Southern Company. The CT-121 scrubbing system features a single $SO_2$ absorption module called the jet bubbling reactor (JBR) made of fiberglass-reinforced plastics where several chemical reactions (absorption/neutralization/oxidation/crystal growth) take place concurrently. The 100 MW flue gas scrubber will use limestone as a reagent to remove up to 95 percent of the inlet $SO_2$ and operate for 27 months beginning in October 1992, producing gypsum as a by-product. Gypsum will be tested for construction and agricultural uses with the majority deposited in a gypsum "stack," a disposal technique used in the phosphate fertilizer industry. Operational testing is to run through late 1994, and will include sustained high $SO_2$ removals, simultaneous particulate removal in the JBR, an alternate limestone, and an alternate higher sulfur coal.

## INTRODUCTION

This paper describes the status of one of the U.S. Department of Energy (DOE) Innovative Clean Coal Technology (ICCT) Projects (Clean Coal II) sponsored and conducted by The Southern Company. The ICCT program is designed to demonstrate clean coal technologies that are capable of retrofitting or repowering existing facilities to achieve significant reduction in sulfur dioxide ($SO_2$) and/or nitrogen oxide ($NO_x$) emissions and increased efficiencies/utilization of domestic coal resources. The technologies selected for demonstration are capable of being commercialized in the 1990's and are expected to be more cost effective than current technologies.

The project objective is to demonstrate innovative applications of technology for cost reduction to Chiyoda's CT-121 $SO_2$ scrubbing process. The CT-121 process is a second-generation, flue gas desulfurization (FGD) process that the Electric Power Research Institute (EPRI) and Southern Company Services, Inc. (SCS) consider to be one of the lowest cost FGD processes in its current commercial configuration. Further cost reductions will make this process even more competitive and attractive to electric utilities or other coal users worldwide.

Georgia Power Company's Plant Yates Unit 1 will host this project. Plant Yates is located on the Chattahoochee River, 40 miles southwest of Atlanta between Newnan and Carrollton. The CT-121 process retrofit for this demonstration project will treat the whole flue gas stream generated by the 100-MW Unit 1 boiler (See Photo 1). A blend of Illinois No. 5 and No. 6 coals containing between 2.5- and 3-percent sulfur will initially be burned with higher sulfur testing possible later in the project.

The Yates project is managed by SCS on behalf of the project cofunders: The Southern Company, DOE, and EPRI. The Southern Company includes Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Savannah Electric and Power, in addition to SCS. SCS provides engineering and research services to all the subsidiaries of The Southern Company.

## PROCESS DESCRIPTION

The CT-121 process is a wet FGD process that chemically removes $SO_2$, achieves simultaneous particulate control, and produces a salable gypsum by-product, thereby eliminating solid waste production. Figure 1 is a schematic flow diagram of the process.

The CT-121 process removes $SO_2$ and particulate matter in a unique limestone-based scrubber called the Jet Bubbling Reactor (JBR). (See Figure 2.) In the JBR, flue gas is bubbled beneath a limestone slurry where $SO_2$ is absorbed and particulate matter is removed from the gas. The agitator assures that fresh slurry is always available in the bubbling or froth zone so that $SO_2$ removal can proceed at a rapid rate. Limestone is added to neutralize acidic intermediate products and to form gypsum. Air is introduced into the bottom of the JBR to completely oxidize the absorbed $SO_2$ to sulfate.

The JBR is designed to allow time for complete reaction of the limestone, for complete oxidation of the $SO_2$, and for the growth of large gypsum crystals. The gas velocity above the gas-slurry contact zone (froth zone) is sufficiently low to allow for separation of slurry from the cleaned gas prior to the gas entering the mist eliminator. This promotes more efficient mist eliminator performance which increases reliability. The fully reacted gypsum slurry is continuously withdrawn from the JBR reservoir and is gravity dewatered in a gypsum stack. This upstream stacking method calls for filling a diked area with gypsum slurry, allowing the gypsum solids to naturally sediment out and removing clear liquid for return to the process.

The CT-121 process offers several distinct advantages over conventional limestone FGD systems:

- Essentially complete limestone utilization which reduces reagent costs, scaling tendency and the volume of sludge produced.
- Complete oxidation of sulfite to sulfate with large crystal growth which results in better solids handling and dewatering characteristics.

- Elimination of chemical scaling in the absorber.
- Elimination of large centrifugal slurry recirculation pumps that consume power and prevent large crystal growth.
- Improvement in mist eliminator and wet stack performance.
- Elimination of the potential for limestone "blinding" due to the reduced presence of aluminum fluoride.
- Reduction in chemical oxygen demand of the gypsum by-product should waste water treatment be required.

The CT-121 process is in widespread commercial use in Japan but has only one commercial application in the United States. At the University of Illinois, a 45-MW CT-121 process began operation in 1988 on a stoker boiler, which produces steam heat for the campus.[1] In Japan, commercial CT-121 processes are used to treat the flue gas from boilers that burn oil or low-sulfur coal. Some of the Japanese oil-fired units do not include particulate control devices upstream of the CT-121 processes. These are atypical of American utility applications.

The Southern Company has first-hand experience with the CT-121 process. In the late 1970's, SCS tested the very first CT-121 system at Gulf Power's Plant Scholz near Tallahassee, Florida, as part of a five-process evaluation. The success of that 23-MW CT-121 test was a big factor in choosing this process for demonstration at Plant Yates.

## PROJECT DESCRIPTION

SCS currently considers the CT-121 process one of the best process alternatives for application in The Southern Company should FGD technology be required for compliance with the Clean Air Act Amendments of 1990. EPRI and SCS have conducted independent studies of FGD process economics and consider CT-121 to be a very attractive candidate for medium- to high-sulfur coal applications. EPRI's process economics are presented in Figure 3.

The purpose of the Yates ICCT project is to demonstrate the CT-121 process on high-ash/high-sulfur U.S. coal using several design modifications that will reduce the estimated cost of the present CT-121 process by as much as 23 percent for power plant retrofit applications and as much as 50 percent for new power plant installations. This will be accomplished while maintaining 90-percent $SO_2$ removal and high particulate removal efficiency. A reusable gypsum by-product will also be produced during the project.

The major cost-reducing design changes to be demonstrated are:

- Corrosion resistant materials of construction.
- Elimination of a spare absorber module.
- Elimination of flue gas reheat.
- Combined $SO_2$ absorption and particulate removal in a single vessel.

In the past, most utility-scale units with CT-121 processes included a prescrubber for control of soluble chloride concentrations and JBRs made of relatively expensive stainless steel. Typically in FGD systems, outlet ducts and chimneys are lined with organic liners or high-grade, expensive alloys. Organic liners normally have to be replaced after a period of time, which adds additional expense and inconvenience; corrosion problems are almost always present even with expensive stainless steels. For the Yates project, the prescrubber has been removed; and the JBR, outlet duct, and chimney will be made of solid fiberglass-reinforced plastics (FRP), which are unaffected by chloride or other corrosion mechanisms normally experienced in FGD processes. A successful demonstration of FRP in this project will confirm the decision to eliminate a prescrubber in the CT-121 process as well as demonstrate a vessel material that is less expensive than stainless steels.

This project is also intended to demonstrate that the CT-121 process using a JBR made of FRP is highly reliable and does not require a spare absorber module to effectively control $SO_2$ emissions. Current Federal New Source Performance Standards (NSPS) require that spare scrubber modules be installed on utility FGD systems if bypass options are to be used in an emergency situation. The Clean Air Act Amendments of 1990 do not specifically require the use of spare absorbers, but some utilities are still reluctant to commit to a compliance plan that does not include spare absorber modules in FGD systems simply for mechanical reliability. This project is intended to demonstrate that the CT-121 process using a JBR made of FRP is highly reliable and does not require a spare absorber module which, of course, reduces capital costs.

Another cost-saving modification to be demonstrated in this project is the elimination of flue gas reheat downstream of the scrubber. The flue gas leaving any wet scrubber is at its water dewpoint and, without reheat, subsequent cooling in the ductwork and stack causes moisture to condense into small droplets. These water droplets absorb traces of $SO_2$ and form a highly acidic mist that can cause severe corrosion in ducts and stacks. These droplets may also "rainout" near the base of the stack, causing damage to surrounding structures and vehicles. To prevent these problems, this project will use operating techniques and equipment designs that physically "knock out" the acid droplets and eliminate the need for costly reheating, saving both capital and operating expenses.

The final cost-saving modification will be an evaluation of simultaneous removal of $SO_2$ and particulate matter in the JBR. Typically, an electrostatic precipitator (ESP) or fabric filter is used upstream of a scrubber to remove particulate matter from the hot, dry flue gas. In the CT-121 process, greater than 90 percent of the $SO_2$ and 99 percent of the particulate matter in the entering flue gas can be removed in the JBR as a result of the torturous path the flue gas undergoes during its "scrubbing." Table 1 shows that less than 0.03 lbs/MMBtu particulate emissions are typical of CT-121 systems. When used in new power plants, the deletion of an ESP or fabric filter will result in substantial capital and operating cost reductions. Thus, the CT-121 process may provide a cost-effective alternative to conventional wet FGD systems <u>and</u> serve as an efficient, no-cost, incidental particulate collector.

The demonstration project is being conducted over an 81-month period and project activities will include environmental monitoring, permitting, design, construction, operation, process evaluation, and gypsum by-product evaluation. The project is organized into three phases:

Phase I - Permitting and Preliminary Engineering; Phase II - Detailed Engineering, Construction, and Start-up; and Phase III - Operation, Testing, and Disposition. Operations are planned for 27 months beginning in October 1992. The remainder of Phase III activities will be dedicated to gypsum by-product utilization and gypsum stack groundwater monitoring studies. The Cooperative Agreement was signed April 2, 1990, and the project completion is projected to be mid-1997. Total estimated cost of the project is $36 million.

## STATUS OF ENGINEERING/CONSTRUCTION ACTIVITIES

With the signing of the Cooperative Agreement in April 1990, engineering activities at Chiyoda and SCS began in earnest. The process design was finalized and preliminary engineering completed in 1991. During the preliminary engineering phase, some modifications were made to the project approach. Originally, a separate duct with a wet fan downstream of the JBR was planned for testing with high ash loadings. After a thorough investigation of alternatives by SCS, Georgia Power, and Chiyoda, a decision was made to eliminate the wet fan and high-ash ductwork. Instead, for approximately 1 year, the ESP will be deenergized and flue gas containing high amounts of fly ash will be sent to the JBR through the new FGD fan. This fan has been designed and constructed to withstand the erosion expected during the high-ash test period. A prescrubber was also originally included in the preliminary design. After review with Chiyoda, a decision was made to eliminate the prescrubber from the design at Plant Yates and to deenergize the ESP in a stepwise manner, with appropriate inspections of the JBR.

The mechanical construction portions of the project were completed in the spring of 1992 but start-up had to be delayed as a result of permitting difficulties with the State of Georgia. The construction of the waste holding area and the gypsum stack could not continue without a permit and had to be suspended in September 1991 for 6 months pending state consideration of the design and operating plan. This caused the gypsum stack-area construction to miss the region's opportunistic weather window and construction was not complete until summer. At that time, the unit was under heavy demand during the

Southern system's peak period and start-up was again delayed until an adequate off-line period could occur in order to complete tie-ins.

Unique to the CT-121 process is its two major FRP vessels which were filament wound onsite and finished with a great deal of hand lay-up techniques. The inlet spray chamber, the JBR, the limestone slurry tank, the chimney, and several lesser tanks are all made of corrosion resistant FRP. The mist eliminator section, however, is a stainless alloy wallpapered, carbon-steel shell with polyvinyl chloride (PVC) vanes and internals which will offer a side-by-side comparison of corrosion resistance between plastics and lined carbon steel. The two major vessels (the JBR and the limestone slurry tank) have been monitored for inservice acoustical emissions to establish a baseline for lifetime evaluation. Finite element analysis and photostress laminate studies are also complementing this baseline effort.

The waste or by-product from the Chiyoda CT-121 process containing the captured flue gas sulfur is a white crystalline solid; calcium sulfate dihydrate or gypsum. This is a far superior solid to traditional scrubber products in all its handling aspects. It is also useful as the main constituent in wallboard, in cement manufacturing, and for selected soil amendment purposes. At Plant Yates, the gypsum by-product will be stored in a pond that becomes a pile by using the upstream stacking method as perfected in the phosphate fertilizer industry. See Photo 2.

## TEST PLAN

The operational testing of the CT-121 process at Plant Yates is scheduled for 27 months. An additional 2-year test period is allocated for gypsum by-product testing, further gypsum stack evaluation, and groundwater monitoring of the gypsum stack area. Two test periods are planned during the operational testing. During the first 13 months, the process will be operated with the ESP fully energized. During the following 14-month period, the ESP will be deenergized in a stepwise manner until the fly ash concentration reaches a level that causes performance problems for the JBR (if this occurs) or until the ESP is fully deenergized. In each period, evaluation of process performance, gypsum stack and by-product reuse, and environmental effects will be measured.

Process Evaluation

The process evaluation in the two test periods will focus on the following areas:

- Process chemistry
- $SO_2$ removal
- Particulate removal
- Equipment components
- FRP evaluation
- Wet chimney
- Economics

Process engineers will remain on site at Yates for the 2-year demonstration program to execute the detailed test plans and provide input when changes are necessary. These engineers will also coordinate the activities of all subcontractors. Daily operations will be the responsibility of specially trained employees from Georgia Power.

Process Chemistry

Chemical analyses of process liquor and waste streams will be conducted on site to characterize the performance of the CT-121 process and provide routine checks of process operation. Any differences in $SO_2$ removal or gypsum quality will be cross-checked against differences observed in the process chemistry. Routine inspections for solids buildup and scaling will also be compared against the relative supersaturation values calculated from the chemical analyses. A detailed sampling and analytical plan, and QA/QC plan will be developed to ensure that high-quality analytical data are collected.

## $SO_2$ Removal

During each test period, brief parametric tests are planned to quantify the operating envelope of the CT-121 process at Plant Yates. The test sequence will involve varying the pH, pressure drop, and gas flow rate and their relative impact on $SO_2$ removal. The results of these tests will be compared to the correlations developed during the prototype CT-121 evaluations at Gulf Power's Plant Scholz and the University of Illinois' Abbott Power Plant.

The majority of the proposed demonstration will be spent collecting and evaluating long-term performance data as the CT-121 process responds to the normal boiler load swings of Yates Unit 1. The current $SO_2$ compliance determination established by the EPA is based on 30-day rolling $SO_2$ emissions measurements. Consequently, the only realistic way to completely characterize the $SO_2$ removal capabilities of an FGD process is to observe its performance over an extended period of time. In this manner, the natural relationship of both controllable and uncontrollable variables can be observed. A sophisticated statistical/time-series analysis of the data will be used to evaluate the long-term $SO_2$ removal efficiency of the Yates CT-121 process.

$SO_2$ removal information will be collected by dry extractive continuous emissions monitoring (CEM) systems on both the JBR inlet and outlet gases. During the start-up of the demonstration, the CEM system will be calibrated by an independent subcontractor using Clean Air Act EPA protocol procedures. After passing these procedures, instrument technicians will use routine quality control checks to ensure that the CEMs continue to produce high-quality data.

## Particulate Removal

As shown in Table 1, the particulate emissions measured from each of the currently operating CT-121 processes have been less than the NSPS limit of 0.03 lbs/MMBtu. These results are generally from plants that have a prescrubber (or low pressure drop precooler) upstream of the JBR. However, the measurements made around the venturi and JBR at the prototype plant at Plant Scholz indicate that the JBR is an excellent particulate scrubber, even for fine particles.

During the Yates project, the particulate removal efficiency of the JBR will be evaluated extensively both with the ESP fully energized and with the ESP deenergized or partially deenergized. The objectives of this evaluation are to:

- Determine the ability of the CT-121 process to meet performance specifications as either a primary or secondary particulate control device.

- Determine the relative contributions of fly ash, sulfuric acid mist, and scrubber slurry carryover to the total particulate emissions from the CT-121 system over a range of operating conditions.

Plans are to collect particulate samples at full and 50-percent load while operating at three different pressure drops (six different operating conditions) during each test period.

Equipment Component Evaluation

SCS plans to track the performance and reliability of individual equipment components and of the CT-121 process as a whole. EPA has established the following performance indices by which FGD process operation information is generally reported:

- Availability Index - Hours that the FGD system is available for operation (whether operated or not) divided by hours in the period, expressed as a percentage.

- Reliability Index - Hours that the FGD system was operated divided by the hours the FGD system was called upon to operate, expressed as a percentage.

- Operability Index - Hours that the FGD system was operated divided by boiler operating hours in the period, expressed as a percentage.

- Utilization Index - Hours that the FGD system was operated divided by total hours in the period, expressed as a percentage.

The hours of operation of the entire process will be tracked via information collected by a digital data acquisition system. The operating parameters will be calculated regularly. All

CT-121 processes built to date have had availabilities greater than 90 percent and reliabilities greater than 98 percent (Table 2).

In addition, the reliability of individual equipment components will also be closely monitored by SCS. This component reliability record will be maintained in a manner consistent with that recommended by EPRI.[2] Data will be compiled when an outage of an FGD component causes (1) a restriction in power generation, (2) an increase in $SO_2$ emissions above the design value, or (3) replacement by an installed spare.

FRP Evaluation

The objectives of the FRP evaluation program at Yates are to:

- Verify that the state of the art in FRP technology today is such that the CT-121 JBR, ducts, and chimney can be designed and constructed to perform reliably for the intended service.
- Determine the type and extent of routine maintenance required in future installations and the degree of unscheduled maintenance that may be incurred.

The overall approach to the FRP equipment evaluation is to observe and record abrasion, corrosion, and structural performance. Thus, visual inspections are a key aspect of this portion of the evaluation. The abrasion/corrosion evaluation will be facilitated by inclusion of multicolored laminate layers in the JBR interior and by installation of different material coupons along the interior surface of the JBR. Structural performance and integrity will be determined through the use of strain gauges, photoelastic laminates, and acoustic emission monitoring techniques, which detect any micro- and macro-crack propagation and structural changes in the material.

## Wet Duct and Chimney Evaluation

The key element of operation without reheat is the design of the mist eliminator, wet duct, and chimney. While several FGD processes are currently operating without reheat, many of them have experienced and some still experience problems with localized acidic liquid deposition from the wet plume after it exits the stack. This can cause local corrosion problems, normally on power plant property. SCS has included engineering fluid-flow modeling as a design basis to successfully operate the 100-MW CT-121 process at Yates without reheat and without liquid fallout. The design included a restriction in flue gas velocity to 50 ft per second in the FRP duct, chimney, liquid collectors, and drains at strategic locations to drain accumulated liquid from the system before it can be re-entrained. Inspection of the ductwork and chimney, and observations of the area around the process will be used to adjust the design should any rainout occur during initial operation of the process.

## Economic Evaluation

Once the process evaluation is complete, SCS will perform an economic evaluation of the CT-121 process with the innovative design features that have been successful. This economic study will be conducted with the detail used in previous process economic studies reported by EPRI.

## Gypsum Stacking

Gypsum produced in the CT-121 JBR, as well as in other forced oxidation FGD processes, has superior mechanical properties to the calcium sulfite sludge produced by conventional FGD processes. The mineralogy, geometry, and particle size of FGD by-product gypsum typically provide settling, dewatering, and structural characteristics that allow easier and more efficient methods of waste disposal than with calcium sulfite sludge. Because of its properties, FGD gypsum can use stacking techniques developed by the phosphate fertilizer industry, which also produces a by-product gypsum.

The stacking technique involves filling a diked area with gypsum slurry that undergoes rapid, natural sedimentation of solids. The filled enclosure is then drained and partially excavated to increase the height of containment dikes. The process of sedimentation, excavation, and raising the perimeter dikes (collectively called the "upstream method" of construction) continues on a regular basis during the active life of the stack. Process water is decanted and continuously returned to the FGD process. Figure 4 shows a conceptual cross section of planned FGD gypsum and gypsum-ash stacks.

In contrast, calcium sulfite sludge is slippery and unstable. Consequently, it must be ponded or landfilled (after dewatering and/or mixing with dry fly ash and lime). These methods are more expensive in terms of required land area (ponding), the need for dewatering equipment/stabilization agents and the need for earth moving vehicles (landfilling). Gypsum stacking combines the advantages of competing disposal methodologies -- low operating cost and equipment requirements of ponding and the smaller space requirements, lower capital cost, and reduced environmental effects associated with waste disposal. Wet stacking of by-product gypsum has been practiced by the phosphate fertilizer industry for more than 25 years. In Florida, more than 20 million tons of phosphogypsum are disposed of annually using the wet stacking method.

Wet stacking has also been used in the FGD industry on a very limited basis. A prototype CT-121 gypsum stack was constructed and operated for a 9-month test period at Gulf Power Company's Plant Scholz.[3] After the work at Scholz, wet stacking of gypsum - fly ash mixtures was successfully tested during a Tennessee Valley Authority (TVA) project at the Widow's Creek Steam Plant in Stevenson, Alabama.[4] TVA has used wet stacking for disposal of gypsum and fly ash at Widow's Creek ever since.

While these earlier projects have shown that FGD gypsum and gypsum-fly ash mixtures can be stacked, the relatively small size of the demonstrations and their limited visibility have restricted the direct transfer of operating and construction experience to other full-scale facilities. Accordingly, specific objectives of the stacking evaluation during the Yates project are to:

- Demonstrate the construction and operation of a wet stacking facility for FGD gypsum and another for FGD gypsum - fly ash on a relatively large scale in a nationally visible project.

- Determine the field handling, stackability, and trafficability characteristics of the FGD gypsum and FGD gypsum - fly ash and develop construction and operation procedures for implementation on a full-scale facility.

- Evaluate the engineering properties of FGD gypsum and FGD gypsum - fly ash from laboratory and field testing and recommend design properties for use in the design of a full-scale gypsum and gypsum - fly ash facility.

Gypsum By-product Evaluation

In addition to advantages in storage and disposal, by-product gypsum has a significantly large market potential. Possible uses for FGD gypsum are essentially the same as those available for natural gypsum -- wallboard, cement, and agriculture. By-product gypsum for the phosphate industry has also begun to receive attention as a potential highway construction material, but its quality limits marketability in many situations.

Present raw gypsum consumption in the U.S. is about 25 million tons and almost 30 percent is imported from Canada and Mexico. Very little of this total is FGD by-product gypsum although Texas Utilities, Tampa Electric, and other utilities are producing large quantities of FGD gypsum targeted for wallboard and cement markets, respectively.[5] The 1983 EPRI FGD By-product Disposal Manual states that almost all by-product gypsum in Japan and (the former) West Germany has been successfully marketed for wallboard and cement applications.[6] This is due, in part, to limited gypsum resources and available land area for disposal in these countries. In the U.S., utilization potential is heavily dependent on local market conditions.

For the Yates project, SCS will work with wallboard and cement companies to test the Yates gypsum on a limited scale. Plans are to collect and ship sufficient gypsum to one or more major wallboard companies for a production run. This test should confirm previous test results and evaluate consistency of the gypsum as well as other considerations. A similar test is also planned for evaluation by a cement company, although neither test plan has yet been developed in detail.

Most of SCS' effort in by-product evaluation for reuse will be directed toward agricultural, which could have an enormous effect on FGD gypsum (and possibly FGD gypsum - fly ash) use. The Southeast is a productive region in agriculture, but most soils in the region represent a major limiting factor to increasing productivity and cultivated acreage. Over many years, soil erosion has removed much of the topsoil, bringing acidic subsoils closer to plant rooting zones and resulting in shallow rooting and greatly reduced yields.[7]

Several methods have been attempted to reduce the chemical and physical limitations of these soils, including deep liming and mixing, as well as surface applications of natural gypsum. Use of gypsum shows great potential, since its soluble nature allows it to be surface-applied rather than mechanically tilled into the soil.[8] It has been successful in reducing soil acidity, improving physical properties through clay flocculation and increased rooting.[9] Researchers at the University of Georgia believe that both perennial and annual crops may benefit from gypsum addition.

The Yates project includes a research program to evaluate the potential for widespread use of by-product gypsum on acidic soils and those soils with physical property limitations. Controlled greenhouse laboratory and field-scale experiments are planned and have the objective of first identifying principles and problem areas in controlled settings before beginning large-scale field studies. The field programs will be necessary to demonstrate real-world effects of applied treatments on the agronomic system. The activities will continue for several years to evaluate the crucial long-term effects expected. Soil, crop, and water components of the system will be monitored to evaluate both agronomic and environmental aspects. The University of Georgia, Department of Agronomy, will serve as the major subcontractor on all by-product evaluation relating to agricultural utilization.

Environmental Evaluation

An extensive environmental evaluation is also planned in the Yates project. Many important environmental aspects have been discussed and will be addressed as part of the process evaluation. (See Photo 3.) These include $SO_2$ and particulate removal efficiency as a function of process variables and the long-term ability of the process to meet its design expectations.

In addition, the groundwater in the gypsum-stack area will be monitored through routine sampling of a seven-well network. Sampling and analysis of these wells is currently being conducted to provide background data for future comparison once the gypsum stack is built and in operation. A survey of the plant life in the vicinity of the plant was conducted before and will also be conducted during CT-121 process operation to better measure the effect of liquid discharge from the chimney should any occur. Environmental reports will be prepared and submitted to DOE quarterly during operation of the process.

## SUMMARY

As compliance requirements become more restrictive and utility ratepayers more demanding, the CT-121 FGD process shows great promise as an $SO_2$ removal technology that offers reduced costs and limited environmental consequences. The Yates Clean Coal Project is one of approximately 40 separate efforts in the DOE Clean Coal Program underway as joint public/private ventures developing coal technologies for tomorrow.

## GLOSSARY

CEM continuous emissions monitoring
DOE Department of Energy
EPA Environmental Protection Agency
EPRI Electric Power Research Institute
ESP electrostatic precipitator
FGD flue gas desulfurization
FRP fiberglass-reinforced plastics
ICCT Innovative Clean Coal Technology
JBR Jet Bubbling Reactor
NSPS New Source Performance Standards
PVC polyvinyl chloride
SCS Southern Company Services, Inc.
TVA Tennessee Valley Authority

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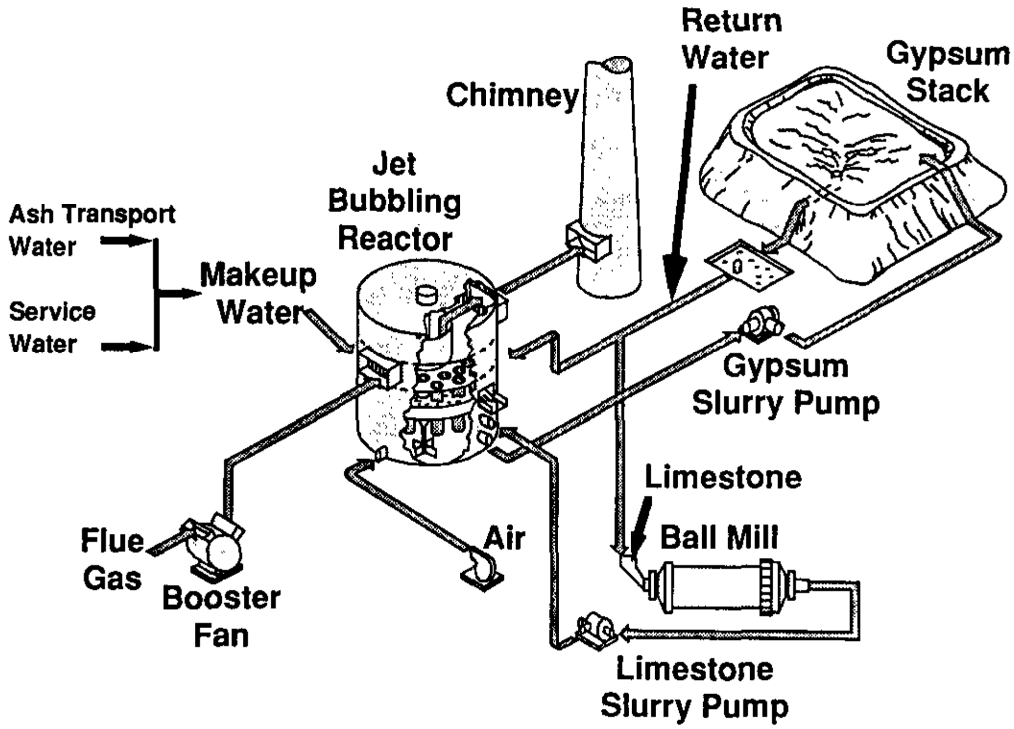


**Figure 1. Process flow diagram for commercial CT-121 process.**

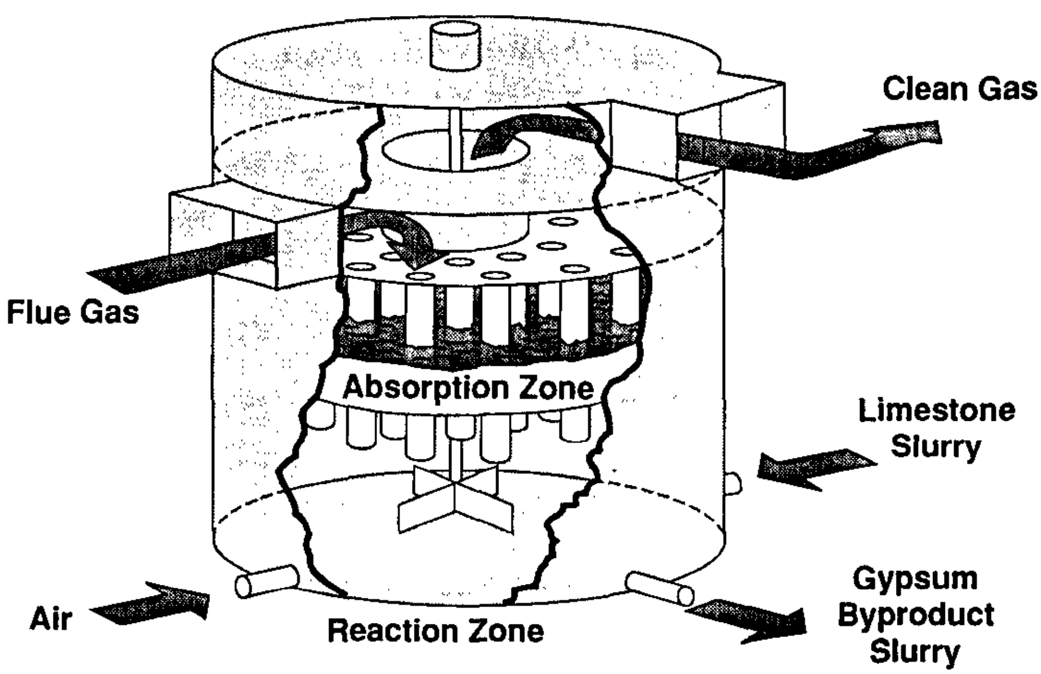


**Figure 2. Schematic of Jet Bubbling Reactor.**

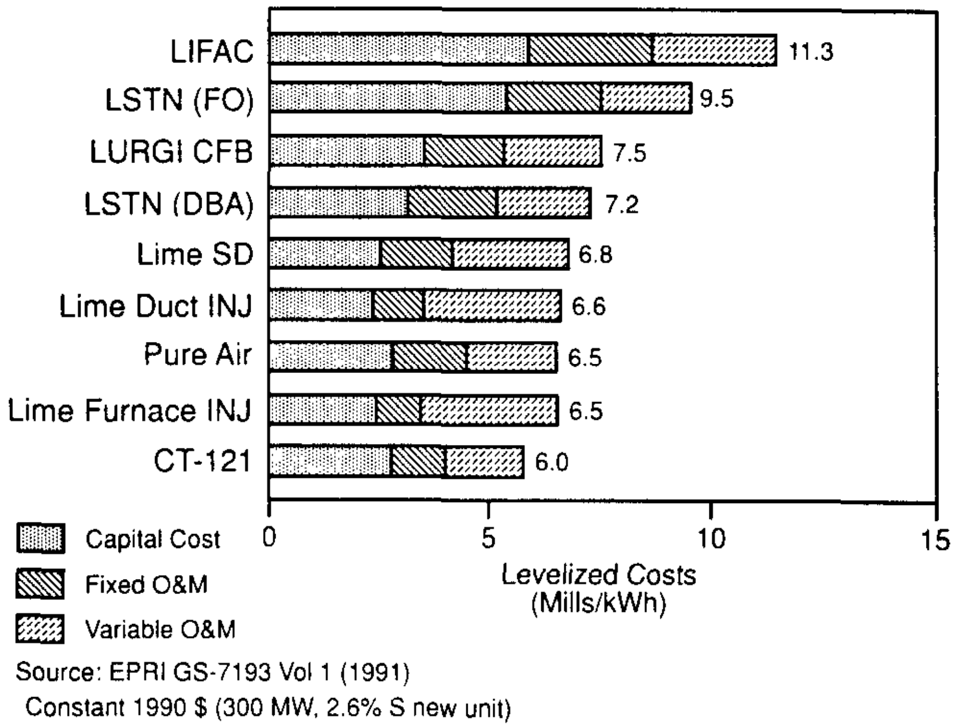


**Figure 3. Process economics for CT-121 application.**

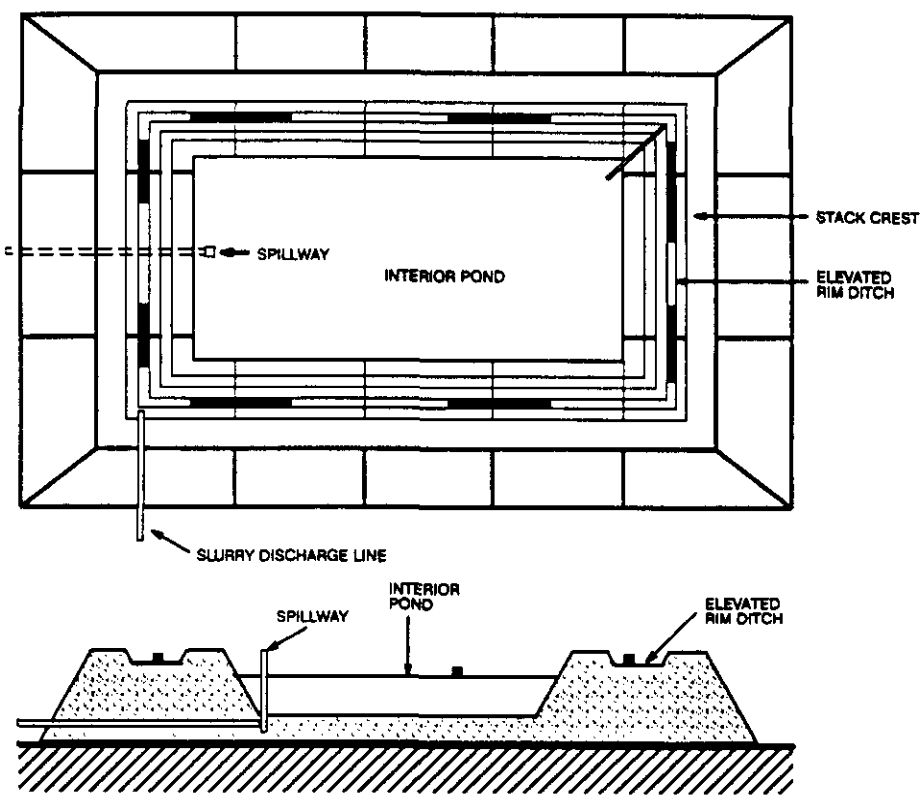


**Figure 4. Conceptual cross section for planned FGD gypsum and gypsum-ash stacks.**

| | | | Particulate Loading* (lbs/MMBtu) | |
|---|---|---|---|---|
| Plant | Fuel | ESP | Inlet | Outlet |
| Scholz | Coal | Off | 6.25 | - |
| Scholz | Coal | Off | 6.080 | - |
| Scholz | Coal | Off | - | 0.029 |
| Scholz | Coal | Off | - | 0.024 |
| Scholz | Coal | Off | 4.31 | 0.029 |
| Scholz | Coal | Off | 7.24 | 0.029 |
| Mitsubishi | Oil | None | 0.15 | 0.023 |
| Toyama | Coal | Yes | 0.08 | 0.006 |
| Nippon Mining | Asphalt | None | 0.15 | 0.029 |

*Source for Scholz data: EPRI CS-1579, Volume 1, Table 6-2. Data from units in Japan are typical values from several tests.

**TABLE 1. CT-121 FGD process — particulate emissions.**

| | Mitsubishi Petrochemical Yokkaichi | Nippon Mining Co. Chita | Toyama Kyodo Electric Power Unit 1 | Toyama Kyodo Electric Power Unit 2 | Kashima Northern Joint Power Co. | Hokuriku Electric Power Kusajima | University of Illinois Abbot |
|---|---|---|---|---|---|---|---|
| *Period:* | | | | | | | |
| *From* | *May 11, 1982* | *Nov. 10, 1983* | *July 9, 1984* | *Aug. 23, 1984* | *Nov 15, 1985* | *July 24, 1987* | *Aug. 18, 1988* |
| *To* | *Dec. 31, 1990* | *Dec. 31, 1990* | *Dec. 31, 1990* | *Dec. 31, 1990* | *Dec. 31, 1990* | *Dec. 31, 1990* | *Sept. 2, 1989* |
| Hours of operation | 71,043 | 57,071 | 48,408 | 47,572 | 39,859 | 17,906 | 8,605 |
| Hours called upon to operate | 71,929 | 57,488 | 48,414 | 47,572 | 40,202 | 17,906 | 8,663 |
| Reliability, % | 98.8 | 99.3 | 100.0 | 100.0 | 99.1 | 100.0 | 99.1 |
| Hours available | 72,208 | 59,475 | 53,387 | 51,248 | 42,905 | 29,142 | 8,536 |
| Hours in period | 75,756 | 62,580 | 56,794 | 55,714 | 44,928 | 30,150 | 9,120 |
| Availability, % | 95.3 | 95.0 | 94.0 | 92.0 | 95.5 | 96.7 | 93.6 |

**Reliability** = Hours the CT-121 process was operated divided by hours the CT-121 process was called upon to operate

**Availability** = Hours the CT-121 process was available for operation (whether operated or not), divided by the hours in the period

**TABLE 2. Availabilities and reliabilities for CT-121 processes built to date.**

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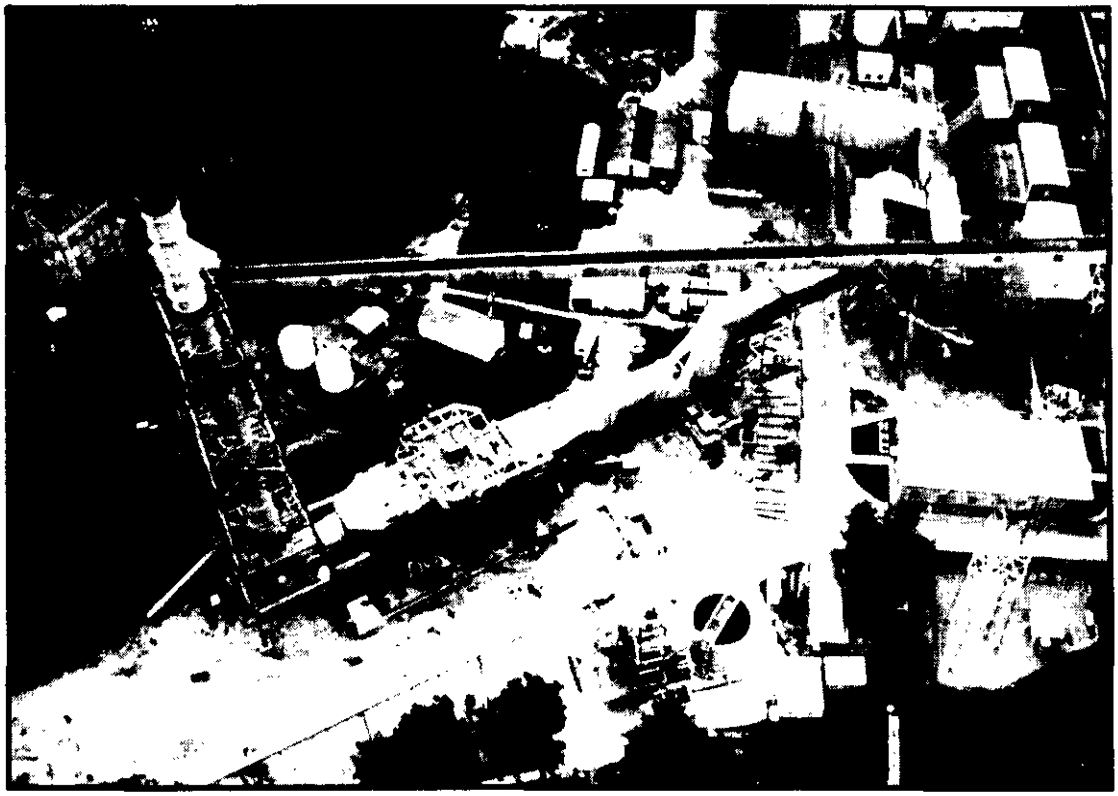

Photo 1. From the bottom unit at the far right, new duct work extends at an angle to the new fan, JBR, and FRP chimney.

Photo 2. Overall view of the three-compartment gypsum disposal area in the foreground with ash/gypsum compartment to the far left, gypsum compartment in the center, and surge pond to the right.

Photo 3. Hypalon plastic liner is being placed in the largest of the two gypsum compartments at Plant Yates.

# $NO_X/SO_2$ REMOVAL WITH NO WASTE - THE SNOX PROCESS

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## ABSTRACT

A no waste, $NO_x/SO_2$ removal technology entitled SNOX is currently being demonstrated in Niles, Ohio at the Ohio Edison Niles Generating Plant. This project is part of the second round of the Department of Energy Clean Coal Technology Program. The demonstration project will treat a 35 MWe slipstream from a 108 MWe boiler burning 3.2% sulfur Ohio coal. The objectives of this four-year project are to demonstrate the SNOX technology using high sulfur coal, qualify and quantify the consumables and products of the process, and verify the operating and maintenance costs.

This paper describes the SNOX Process and the Niles Demonstration Project. Initial results from the eighteen month testing program and a discussion of the market potential of the SNOX Process are also presented.

## INTRODUCTION

International environmental and pollution abatement industries are rapidly developing technologies which offer electric utilities cost-effective alternatives that will exceed the requirements of current and pending environmental legislation. These technologies offer increased pollutant removal efficiencies, reduced reagent requirements, minimized waste streams, and lower operating and maintenance costs. One such process is a catalytic de-$NO_x$/de-$SO_x$ process being demonstrated and offered by Asea Brown Boveri/Environmental Systems [ABB/ES] entitled SNOX.

The SNOX Process was developed in Denmark by Haldor Topsoe A/S and will be offered under license in North America by ABB/ES. The U.S. Department of Energy [DOE], the Ohio Coal Development Office [OCDO], Ohio Edison, Snamprogetti USA, and ABB/ES are participating in a demonstration of this advanced technology through the Clean Coal Technology Program. As part of the National Energy Strategy, the Clean Coal Technology Program (CCT) is designed to take full advantage of the enormous low cost coal reserves available in the United States by helping coal reach its full potential as a source of energy for the nation and the international marketplace. Attainment of this goal depends upon the development of highly efficient, environmentally sound, competitive coal utilization technologies responsive to diverse energy markets and varied consumer needs. The CCT Program is an effort jointly funded by government and industry whereby the most promising of the advanced coal-based technologies are being moved into the marketplace through demonstration. The CCT Program is being implemented through a total of five competitive solicitations, four of which have been completed. The SNOX Demonstration Project which was selected in the second round of CCT solicitations is located at the Ohio Edison Niles Generating Plant in Niles, Ohio, and is one of three SNOX plants currently in operation. The additional plants include a 300 MWe unit in Denmark and a 35 MWe unit in Italy.

The SNOX Process utilizes selective catalytic reduction [SCR] for $NO_x$ control and a sulfuric acid recovery technology for $SO_2$ removal. The design features of the SNOX Process are expected to provide high efficiency $NO_x$ and $SO_2$ removal, minimal particulate emissions, no liquid or solid waste production, and increased thermal efficiency of the boiler.

The key principle of this forty-eight month \$31M project is to demonstrate the SNOX Process using high-sulfur domestic coal. Extensive parametric testing will serve to quantify the SNOX technology's impact on waste generation, gaseous and particulate emissions, sulfuric acid production, and thermal energy recovery.

## THE SNOX TECHNOLOGY

The SNOX technology consists of five process areas as follows: particulate collection, $NO_x$ reduction, $SO_2$ oxidation, sulfuric acid condensation, and acid conditioning. Heat addition, transfer, and recovery represent a significant portion of the SNOX system as well. Figure 1 depicts a typical full scale SNOX Process flow diagram integrating each of the above process areas.

Flue gas leaving the air preheater [see Figure 1] is treated in a particulate control device and passed through the cold side of a gas/gas heat exchanger (GGH) raising the flue gas temperature to above 700°F. A mixture of ammonia and air is added to the flue gas prior to the SCR where nitrogen oxides are reduced to free nitrogen and water. The flue gas leaves the SCR and, after a slight temperature increase, enters the $SO_2$ Convertor which oxidizes $SO_2$ to sulfur trioxide ($SO_3$). The $SO_3$ laden flue gas is subsequently cooled as it passes through the hot side of the GGH. Flue gas exists the hot side of the GGH and enters a falling film condenser where the flue gas is cooled to a temperature below the sulfuric acid dewpoint. Sulfuric acid condenses from the gas phase on the interior of borosilicate glass tubes and is collected, cooled, diluted, and stored for shipment. Ambient air used as the cooling medium enters the WSA [Wet Sulfuric Acid] Condenser at ambient temperatures and exits at 400°F. This heated air may be used for process support and furnace combustion air after collecting more heat through the air preheater.

Particulate Collection

The selection of a highly efficient particulate removal system for use in the SNOX Process has benefits other than low outlet dust emissions. The SNOX Process uses a catalyst in the $SO_2$ Convertor that characteristically traps 90% of all particulate and dust contained in the flue gas. As the catalyst is fouled with particulate, the $SO_2$ Convertor pressure drop increases and a catalyst screening procedure must be implemented to reduce the $SO_2$ pressure drop to a more satisfactory level. Higher particulate loads will require more frequent screening of the $SO_2$ catalyst, and, therefore, there is incentive to choose a highly efficient particulate collection device.

The SNOX Demonstration Project in Niles, Ohio utilizes a fabric filter with GoreTex® membrane bags designed to achieve low dust emission requirements. By using a high efficiency dust collector combined with the dust retention characteristics of the $SO_2$ Convertor, particulate emissions from the SNOX Process have been demonstrated to be less than .0004 grains/dscf which is far below any current government regulation or standard.

Although a high efficiency dust collector has benefits related to catalyst screening costs, such a piece of equipment is not an essential feature of the SNOX Process. The SNOX plant in Italy, for instance, uses an electrostatic precipitator (ESP) and will require $SO_2$ catalyst screening more frequently. The SNOX Demonstration Project in Niles, Ohio, using a fabric filter with GoreTex® bags, is expected to require $SO_2$ catalyst cleaning only once each year.

Nitrogen Oxide Reduction

Exiting the particulate collection device and prior to entering the SCR, the temperature of the flue gas is increased to over 700°F through the GGH. An ammonia ($NH_3$) and air mixture is introduced to the flue gas stream through a proprietary nozzle grid arrangement also located upstream of the SCR. The ammonia injection grid is designed to provide controlled stoichiometric ratios of $NH_3$ to $NO_x$ over the cross-section of the SCR inlet ductwork.

By controlling the ammonia injection, the $NO_x$ removal efficiency may be optimized and ammonia "slip" across the SCR can be minimized. Any excess ammonia, however, will be oxidized to $NO_x$, water, and $N_2$ in the $SO_2$ Convertor downstream of the SCR.

Flue gas entering the SCR contacts the Haldor Topsoe DNX monolithic catalyst which has been demonstrated in commercial plants throughout Europe to remove 97% of the entering $NO_x$. The reduction of NO follows Equation 1.

$$NO + NH_3 + 0.25\ O_2 \Rightarrow N_2 + 1.5\ H_2O + 410\ \text{kJ/mole}\ (389\ \text{Btu/mole}) \qquad [1]$$

The small amount of $NO_2$ present in the flue gas is reduced similarly.

The SNOX Process offers one distinct advantage over other SCR technologies using ammonia. In an effort to limit ammonia "slip" past the SCR to 5 ppm or less and thus avoid ammonium salting in the ductwork, other technologies are limited to molar ratios of $NH_3/NO_x$ of less than 1.0. The $NO_x$ removal of these processes is consequently limited to less than 90%.

In the SNOX Process, however, any ammonia not reacted in the SCR will be oxidized in the $SO_2$ Convertor. Consequently, stoichiometric ratios of 1.00 to 1.05 may be used resulting in higher $NO_x$ removal efficiencies without the negative downstream effects of higher ammonia concentrations. However, to maximize overall system $NO_x$ removal and control ammonia costs excess ammonia should be minimized.

Sulfur Dioxide Oxidation

Flue gas exiting the SCR is heated slightly and enters the $SO_2$ Convertor contacting the Haldor Topsoe VK 38 sulfuric acid catalyst. The Haldor Topsoe VK 38 catalyst has been used successfully in the U.S. sulfuric acid industry for the past decade. Over 95% of the entering $SO_2$ is oxidized as shown in Equation 2.

$$SO_2 + 0.5\ O_2 \Rightarrow SO_3 + 98\ \text{kJ/mole}\ (93\ \text{Btu/mole}) \qquad [2]$$

The efficiency of the Haldor Topsoe VK 38 catalyst is not affected by the presence of water vapor or chlorides in concentrations of 50% and several hundred ppm, respectively. The $SO_2$ catalyst will also oxidize most of the carbon monoxide (CO) and hydrocarbons present in the flue gas to carbon dioxide ($CO_2$) and water.

As previously discussed, the VK 38 catalyst must be cleaned at certain intervals depending upon the dust load entering the $SO_2$ Convertor. The catalyst cleaning procedure is a simple process consisting of isolation and removal of the catalyst from a single catalyst bed, screening the catalyst, and refilling the bed with the screened catalyst. The catalyst cleaning procedure may be automated and performed while the SNOX Process is operating. The screening procedure will remove virtually all flyash and dust from the surface of the pelletized $SO_2$ catalyst. Catalyst loss during screening is estimated at 2-3%.

Sulfuric Acid Condensation

The hydration and condensation of the $SO_3$ leaving the $SO_2$ Convertor is accomplished in two steps. As the flue gas passes through the hot side of the GGH cooling approximately 300°F, the $SO_3$ is hydrated to sulfuric acid vapor as shown in Equation 3:

$$SO_3 + H_2O \rightleftharpoons H_2SO_4\text{ (vapor)} + 100\text{ kJ/mole (95 Btu/ mole)} \qquad [3]$$

During the cooling phase, the flue gas temperature is maintained well above the sulfuric acid dewpoint to avoid acid condensation and corrosion of the ductwork.

Leaving the secondary side of the GGH, the flue gas enters the WSA Condenser. The flue gas passing through the WSA Condenser is transported and cooled inside borosilicate glass tubes. The design and operating conditions of the condenser make possible the near complete condensation and capture of sulfuric acid at concentrations of 94 to 97 wt. % according to the following equation.

$$H_2SO_4\text{ (vapor)} \rightleftharpoons H_2SO_4\text{ (liquid)} + 69\text{ kJ/mole (65 Btu/mole)} \qquad [4]$$

The cooled flue gas exits the WSA Condenser at approximately 210°F containing about 5 ppm of uncollected sulfuric acid mist. The condensed sulfuric acid product is collected in an acid brick lined trough in the bottom of the WSA Condenser and allowed to flow by gravity into the acid conditioning and storage system.

Acid Conditioning and Storage Systems

The sulfuric acid product enters the acid conditioning system at a temperature of 400°F. The acid is then circulated through a thermoplastic lined piping system comprised of a holding tank, circulation pumps, and a water cooled tube and shell heat exchanger. The function of this circulation loop is to cool the sulfuric acid to more manageable temperatures [70 - 100°F] and allow dilution of the acid to the commercially traded concentration of 93.2 wt.%.

Heat Addition, Transfer, and Recovery

Heat addition, transfer, and recovery are particularly important to the SNOX Process. The SNOX Process requires heat only to trim the flue gas temperature between the SCR and the $SO_2$ Convertor. The most efficient and cost-effective source of this heat in the utility environment is anticipated to be steam, but natural gas or oil may be effectively utilized.

The GGH in the SNOX Process facilitates the use of the high temperatures in the process area in an economic manner by transferring sensible heat in the treated flue gas stream to the process inlet stream. Selection of the type of heat exchanger is important since any leakage of flue gas across the GGH would bypass the process reactors and result in lower measured system removal efficiencies. As a result of the high leakage rates associated with rotary heat exchangers in smaller capacities, a zero leak heat pipe heat exchanger was selected for use at the Niles Demonstration Project.

The SNOX Process generates recoverable heat in several ways. Each reaction with respect to $NO_x$ and $SO_2$ removal is exothermic - $NO_x/NH_3$ reactions, $SO_2$ oxidation, $SO_3$ + water to form gaseous sulfuric acid ($H_2SO_4$), and condensation of the sulfuric acid. This heat plus any support heat added after the SCR is recovered in the WSA Condenser cooling air for use in the utility system furnace as combustion air. A small percentage of this heat is used for the SNOX plant auxiliary equipment such as ammonia evaporation and dilution, burner combustion air, and preheating the catalyst screening equipment.

## NILES DEMONSTRATION PROJECT

The SNOX Demonstration Project is located at the Ohio Edison Niles Generating Plant in Niles, Ohio. The Niles Generating Plant provides electricity to approximately 9,000 square miles in Northeastern Ohio and Western Pennsylvania. The SNOX project is one of ten Clean Coal Technology projects being cosponsored by Ohio Edison. Such experience with promising environmental technologies will aid Ohio Edison in planning more efficiently and effectively for pending acid rain legislation.

Ohio is one of the largest coal consuming and producing states with over seven billion tons of recoverable reserves of high-sulfur coal. Compliance with Clean Air Act requirements has resulted in significant declines in the demand for Ohio's high-sulfur coal. Consequently, Ohio has become a strong supporter of the development of clean coal technologies.

The Niles Generating Plant is one of ten power plants in the Ohio Edison system. The main power plant structure houses two cyclone coal-fired steam electricity generating units with a total net capacity of 216 MWe. The boiler units burn high sulfur coal with a capacity factor of 67%. The plant utilizes two ESP's to control particulate emissions, and the flue gases from both units are dispersed through a single 393 foot chimney.

The SNOX project treats approximately one third of the flue gas stream from the Unit 2 boiler or 16% of the total flue gas from the plant. The flue gas treated by the SNOX plant is extracted prior to the Unit 2 ESP. Flue gas treated by the SNOX plant will be returned to the existing Ohio Edison stack chimney. Figure 2 outlines the process flow diagram for the SNOX plant, and Figure 3 is a general arrangement of the process equipment relative to the existing Ohio Edison plant.

The equipment description numbers shown in Figure 3 correspond to the following equipment:

| | |
|---|---|
| H - 201 | First support burner |
| A - 202 | Baghouse |
| V - 101 | Venturi |
| K - 203 | Booster Fan |
| R - 206 | SCR Reactor |
| R - 208 | $SO_2$ Convertor |
| E - 204 | Gas/Gas Heat Exchanger |
| E - 209 | WSA Condenser |
| K - 230 | Cooling air fan |
| S - 270 | Air vent stack |
| H - 210 | Third support burner |
| P - 223A/B | Acid storage tanks |
| P - 224 | Acid transfer pump |
| P - 230 | Ammonia pump |
| B - 225 | Ammonia storage tank |
| X - 280 | Catalyst screening system |

The execution of the SNOX Demonstration Project is divided into three phases spanning forty-eight months. These phases are identified as follows:

| | |
|---|---|
| Phase I: | Design and Permitting |
| Phase II A: | Long Lead Procurement |
| Phase II B: | Construction and Start-Up |
| Phase III: | Operation, Data Collection, Reporting and Disposition |

Phase I of this project, Design and Permitting, may be further divided into basic engineering, detailed engineering, and permitting. Basic engineering was completed in July of 1990, followed by the completion of detailed engineering near the end of 1990. All environmental permits applicable to the project have been obtained from the Ohio EPA.

Phase II was comprised of the procurement of long lead-time items such as the baghouse, high temperature steel, gas/gas heat exchanger, and WSA Condenser. These items were purchased at the beginning of detailed engineering and arrived at the SNOX plant for installation between February and May of 1991.

Site preparation and installation of foundations began in November of 1990 and construction was completed in November of 1991. The project is currently in Phase III of the program - Testing - which will span approximately eighteen months.

## OBJECTIVES AND TEST PROGRAM

The primary goal of the SNOX Demonstration Project is to apply the SNOX technology and evaluate its performance in a North American high-sulfur coal-fired commercial application. The three key objectives are as follows:

(A). Demonstrate $NO_x$ and $SO_2$ removals of 90 and 95%, respectively.
(B). Demonstrate the commercial quality of the product sulfuric acid.
(C). Perform an economical and technical characterization of the technology.

The following secondary objectives are necessary to establish a foundation for the technical and economic evaluation of a commercial application of the SNOX technology.

(A). Execute parametric test batteries on key pieces of equipment
- Fabric filter
- SCR system
- $SO_2$ Convertor
- WSA Condenser
- Gas/Gas Heat Exchanger
- Catalyst screening unit

(B). Quantify process consumptions
- Power
- Natural gas
- Catalysts
- Cooling water
- Potable water
- Ammonia

(C). Quantify process productions
- Sulfuric acid
- Heat

(D). Quantify personnel requirements

(E). Evaluate all materials of construction

An intensive parametric test program involving continuous process monitoring and manual testing of process components has been developed for an eighteen month program. Figure 4 displays the expected schedule for the test program. Unless explicitly defined and approved by the project participants, all test procedures will conform to industry standards such as those by the EPA, ASTM, EPRI, APHA, AWWA, and WPCF.

After initial start-up, a series of baseline tests designed to identify the characteristics of the flue gas slipstream being supplied to the SNOX system were completed. During the period of baseline testing, manual calibration and verification of several process instruments such as the venturi flow monitor, the acid mist analyzer, pressure and temperature monitors, and tank level indicators were also completed.

Having completed the pretesting and calibration phase, Activities 3 through 5f, as shown in Table 1, are being executed to identify the operational limits of the SNOX plant. Job numbers 11, 23, and 31 in Figure 4 represent scheduled two-week outages that will allow a complete evaluation and documentation of equipment and material conditions in the system.

Beginning in February of 1993, the SNOX plant will be operated continuously at optimum conditions for a two-month period. The optimized process conditions for this operating period will be determined by the individual component tests currently underway. This test run is designed to reflect the SNOX Process' maximum capabilities for this utility installation.

## TEST RESULTS

The results presented below were compiled after two months of operation of the SNOX plant and are part of the parametric testing program previously discussed. Each of the five key process areas associated with the SNOX technology have been evaluated in the early stages of the test program. The results presented below are to be considered preliminary. The SNOX unit has currently undergone little process tuning, and as more information is generated from the test program the data presented below is expected to improve.

| SNOX DEMONSTRATION PROJECT AVERAGE TEST RESULTS | |
|---|---|
| System Load | 5680 lb/min |
| Inlet $NO_x$ | 616 ppm |
| Inlet $SO_2$ | 2056 ppm |
| Outlet $NO_x$ | 35 ppm |
| Outlet $SO_2$ | 88 ppm |
| $H_2SO_4$ Produced | 28 tons/day |

Table 2

Selective Catalytic Reactor

The test results in Table 2 indicate a $NO_x$ removal efficiency of 94%. The flue gas flow and $NO_x$ distribution in the ductwork upstream of the SCR have been evaluated, and the ammonia injection system will be trimmed to allow a proper distribution of ammonia into the system. The trimming of the ammonia grid is expected to increase the system $NO_x$ removal efficiency to above 95%.

$SO_2$ Convertor

As shown in Table 2, the SNOX system $SO_2$ removal efficiency has been demonstrated to be 96%. During the next phases of the test program, data regarding the temperature and flow entering the $SO_2$ Convertor will be accumulated and allow process adjustments that will enhance the system $SO_2$ removal efficiency.

WSA Condenser

The WSA Condenser is operating at design sulfur recovery and producing a high quality [94 wt.%] sulfuric acid product.

Fabric Filter

Early test results indicate baghouse outlet dust emissions to be within the range of .0003-.0010 grains/dscf. The measured low baghouse particulate levels combined with the dust retention characteristics of the $SO_2$ Convertor are expected to merge and meet the target SNOX system outlet particulate loading of less than .0004 grains/dscf.

Process Consumptions

Early indications show that the SNOX plant uses approximately 1% of the utilities power production for complete plant operation. Figures for natural gas, catalysts, cooling water, potable water, and ammonia were not available for inclusion in this report.

Process Productions

Sulfuric Acid: At full load steady-state operations, the SNOX plant is producing twenty eight tons of sulfuric acid daily. Each shipment of product acid is analyzed and typically contains less than 20 ppm of iron and has a concentration of 94 wt.%. The acid is exceptionally clear.

Heat Recovery: The SNOX plant is currently discharging 340°F air from the cooling side of the WSA Condenser. This temperature increase from ambient conditions to 340°F is a result of the recovered heats of reaction, input from the natural gas burners, and additional cooling of the flue gas. As the SNOX plant undergoes further testing, estimates regarding the introduction of this heat into the air preheater and the subsequent increase in boiler efficiency will be generated.

Operating Personnel Requirements

The SNOX plant is operating seven days a week, twenty four hours each day with only one operator required for each eight hour shift. The plant operator has the ability to remotely manipulate each piece of process equipment from the distributed control system located in the SNOX control room.

Test Results from 300 MWe European Installation

In November, 1991, the first full scale SNOX plant was inaugurated by the Danish Minister of the Environment. The plant, located in Northern Jutland, Denmark, has been in operation for approximately seven months. The plant has been tested at boiler loads ranging from 25% to

107% while burning coal with 0.5% to 2.8% sulfur. A portion of the coal being burned in this facility is mined in Western Pennsylvania and shipped to Denmark.

The $NO_x$ and $SO_2$ emission reductions are 92% and 95%, respectively, and the sulfur is being recovered as 93 wt.% sulfuric acid. Therefore, the 300 MWe plant in Denmark is exceeding the SNOX standards of 90% $NO_x$ reduction and 95% $SO_2$ reduction.

## MARKET POTENTIAL

The advantages of the SNOX technology over other de-$NO_x$/de-$SO_x$ technologies are being evaluated through the operation of the SNOX Demonstration Project and continue to distinguish the SNOX Process as a superior technology for the coming decade of heightened environmental concern. The SNOX Demonstration Plant uses no alkali reagent to achieve $SO_2$ removal and only stoichiometric quantities of $NH_3$ for large reductions in $NO_x$. Further, the only by-product is a highly valuable commercial sulfuric acid.

As expected from the operating data of the European SNOX plants, the SNOX plant in Niles, Ohio will establish new standards for low emissions. A comparison of the SNOX technology with other flue gas cleaning technologies indicates that the SNOX Process is capable of lower emissions than comparable processes.[1] While other technologies may improve upon emissions, the SNOX Process with a combined $NO_x$ and $SO_2$ catalyst system is expected to outperform competitors. Also, the SNOX Process will oxidize hydrocarbons and decrease $CO_2$ as a result of increased boiler efficiency in a large integrated design.

### Waste Products

Because the SNOX Process produces saleable sulfuric acid and the flue gas $NO_x$ is converted to nitrogen and water, no waste materials are generated from the removal of $NO_x$ and $SO_2$. Flyash is still produced as a waste product, but in no larger quantities than other technologies. Also, a small amount of catalyst and flyash must be sent to a catalyst processor as a result of the catalyst screening procedure discussed earlier in this paper, and at the end of the useful life of both the $NO_x$ and the $SO_2$ catalyst, the catalyst must also be returned to a catalyst processor. The $SO_2$ catalyst is estimated to have a life of 10 years, while the $NO_x$ catalyst is expected to last between

3 and 6 years.[2] This estimated information will be verified through the operation of the SNOX plant in Niles, Ohio.

Sulfuric Acid

The U. S. Bureau of Mines reports that sulfuric acid consumption has been regarded as one of the best indexes of a nation's industrial development, and in 1990, the United States remained the world's largest producer and consumer of sulfuric acid. In 1990, the total sulfuric acid consumption in the U. S. was 38.54 million tons. The leading industrial end users of sulfuric acid are shown in Table 3.

END USE OF SULFURIC ACID
(% of total consumption)

| | |
|---|---|
| Phosphate Fertilizers | 69% |
| Copper ores | 5% |
| Petroleum | 3% |

Table 3

Agriculture is the largest end-user of sulfuric acid accounting for approximately 69% of the United States consumption. Within the agricultural industry, 90% of the sulfuric acid demand was used in the manufacture of phosphate fertilizers. The phosphate fertilizer industry is expected to grow substantially through 1995 which will allow continued growth in the domestic sulfuric acid industry. Recent increases in fertilizer exports and in the development of sulfuric acid in mineral leaching operations, particularly copper, have helped to stabilize the sulfuric acid market and encourage suppliers of the continued need for sulfuric acid.

As environmental concerns become more visible, the by-product sulfuric acid producing technologies such as SNOX could produce an estimated 30 million tons of sulfuric acid annually. The U.S. Bureau of Mines estimates that 85% of the world's sulfur production will eventually come from environmentally regulated sources. Therefore, technologies such as SNOX are predicted to be an extremely attractive alternative to traditional technologies.

## SUMMARY

The SNOX technology is a totally catalytic process designed to remove $NO_x$ and $SO_2$ from utility flue gases. No reagents are employed in the removal of $SO_2$ and a small amount of ammonia is necessary for the selective catalytic reduction of $NO_x$. Early test results from the SNOX plant in Niles, Ohio are encouraging, and as the plant is brought to full design conditions, the SNOX unit is expected to produce results above those targeted.

The SNOX Process has several distinct advantages over other de-$NO_x$/de-$SO_x$ processes and conventional environmental technologies which will rate the SNOX Process as a desirable and superior technology in the coming decade.[3] These advantages, which are being commercially demonstrated in the SNOX project in Niles, Ohio include:

- High $NO_x$ removal with low risk of ammonium salt scaling
- High $SO_2$ removal with no alkali reagents
- Low particulate emissions
- Only by-product is commercial grade sulfuric acid

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**SNRB - $SO_2$, $NO_x$ and Particulate Emissions Control with a High Temperature Baghouse**


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## INTRODUCTION

The $SO_x$-$NO_x$-Rox Box (SNRB) is an advanced air pollution control process patented by Babcock & Wilcox that significantly reduces the emissions of the oxides of sulfur ($SO_x$) and nitrogen ($NO_x$) as well as particulate matter (designated as Rox) from coal-fired boilers. The process employs a high-temperature, pulse-jet baghouse (Box) and combines $SO_x$ removal through injection of an alkali sorbent (such as hydrated lime or sodium bicarbonate), $NO_x$ reduction through ammonia injection and selective catalytic reduction (SCR) and particulate collection. The advantages of the process include: multiple pollutant emission control, compact integration of control technologies into a single unit; dry sorbent and by-product handling; improved SCR catalyst life due to lowered $SO_x$ and particulate levels; and the potential for improved boiler efficiency.

Preliminary results from initial operation of the 5-MWe demonstration facility indicate emission reduction performance in excess of the initial project goals of 70% $SO_2$ removal, 90% $NO_x$ reduction and NSPS particulate emissions compliance. To date, $SO_2$ emission reductions of up to 85% have been observed at a Ca/S ratio of 2 and baghouse operating temperature of 850°F. Greater than 90% $NO_x$ reduction has been obtained at an $NH_3/NO_x$ ratio of 0.9. Particulate emissions at the baghouse outlet have consistently been less than 0.03 lb/$10^6$ Btu.

The initial results and operating experience at the 5-MWe SNRB demonstration facility have been encouraging. High emission control efficiencies have been achieved for $SO_2$, $NO_x$, and particulates. Plant engineering integration, economic evaluation, and market assessment activity remains to be completed in the current CCT project. The challenge for the project team now is to move the technology through the next phase of commercial development to a larger industrial or utility application.

Future testing will focus on assessment of alternative bag filter fabrics and optimization of $SO_2$ removal performance. These two areas appear to present the greatest opportunity for reducing operating and capital costs associated with the SNRB technology.

The current project was selected for award in the second round of the DOE Clean Coal Technology (CCT) Program. The overall objective of the project is to demonstrate the commercial feasibility of the SNRB technology through operation of a 5-MWe slipstream pilot employing commercial-scale filter bag/catalyst assemblies. Integrated optimization of $SO_2$ and $NO_x$ removal efficiencies will be achieved by control of the baghouse operating conditions, sorbent and ammonia injection rates, and $SO_2$ sorbent selection. Operating experience at the demonstration will identify potential process design and control limitations which may require modification for the next, larger scale installation. Although the dry byproduct solids will be disposed of in a solid waste landfill, potential uses for the byproduct will be explored for further developmental activity.

The SNRB Flue Gas Cleanup Demonstration Project is co-sponsored by the U.S. Department of Energy (DOE), the Ohio Coal Development Office (OCDO), and the Electric Power Research Institute (EPRI). Babcock & Wilcox (B&W) is the SNRB technology developer and prime contractor for the demonstration project. Ohio Edison is hosting the slipstream demonstration at the R. E. Burger plant near Shadyside, Ohio. The City of Colorado Springs Utilities is hosting a filter fabric durability pilot test at the Martin Drake Plant in Colorado Springs, Colorado. High-temperature filter bags for the demonstration were provided at reduced cost by 3M. Owens Corning Fiberglass also provided filter bags at reduced cost for the alternative fabric durability test. The $NO_x$ reduction catalyst was provided with cost sharing by Norton Chemical Process Products.

Following selection of the proposal in the second round of the Clean Coal Technology Program, the DOE/B&W Cooperative Agreement was signed in December, 1989. The OCDO Grant Agreement was completed in April, 1990. The SNRB CCT program consists of three phases.

Phase 1 included design and permitting activities for the demonstration facility. Pilot testing of two bag/catalyst arrangements was completed in Phase 1 at B&W's Alliance Research Center to finalize the demonstration facility design. A second pilot test series to evaluate the durability of three high-temperature bag fabrics was added to the base project in 1991. This pilot pulse-jet baghouse in Colorado Springs has been operated for about 3,000 hours, and operation is expected to continue through the end of 1992.

Phase 2 involved procurement of equipment and materials for the demonstration, construction, and start-up of the facility. This Phase ended with completion of start-up activity in May, 1992.

Operation and performance testing of the demonstration facility will be completed in Phase 3 of the project. This phase includes a detailed analysis of the process economics, as well as an engineering analysis to define the modifications required to retrofit SNRB into an existing generating plant. Removal of the slipstream demonstration equipment and restoration of the Ohio Edison site is also planned for Phase 3. This phase is currently scheduled to be completed in April, 1993.

The current contract budget is $11.9 million. The original project work scope has been amended to incorporate evaluation of alternative bag fabric durability in a pilot baghouse. Additional work scope has been proposed to include testing of an alternative bag material in the 5-MWe demonstration facility and for evaluation of air toxics emission control efficiency of the SNRB process relative to the base plant ESP. The additional testing in the demonstration facility will be completed in Phase 3.

**TECHNOLOGY DESCRIPTION**

B&W has developed and patented the combined emissions control process known as the $SO_x$-$NO_x$-Rox Box™ (SNRB). Briefly, this process consists of the injection of ammonia and either a calcium- or sodium-based sorbent upstream of a high-temperature baghouse which contains woven, high-temperature bags and a selective catalytic reduction (SCR) catalyst (see Figure 1). The SNRB process has the potential for simultaneously achieving 70-90% $SO_2$ removal, 90% $NO_x$ removal, and 99.9+% particulate collection from high sulfur coal flue gas. This level of particulate collection efficiency reflects compliance with the New Source Performance Standard (NSPS) of 0.03 lb particulates/ million Btu for coal-fired boilers. Integration of the three removal processes into one unit results in lower capital and operating costs, operating simplicity, and lower space requirements when compared to a combination of separate flue gas desulfurization, selective catalytic reduction, and particulate removal systems.

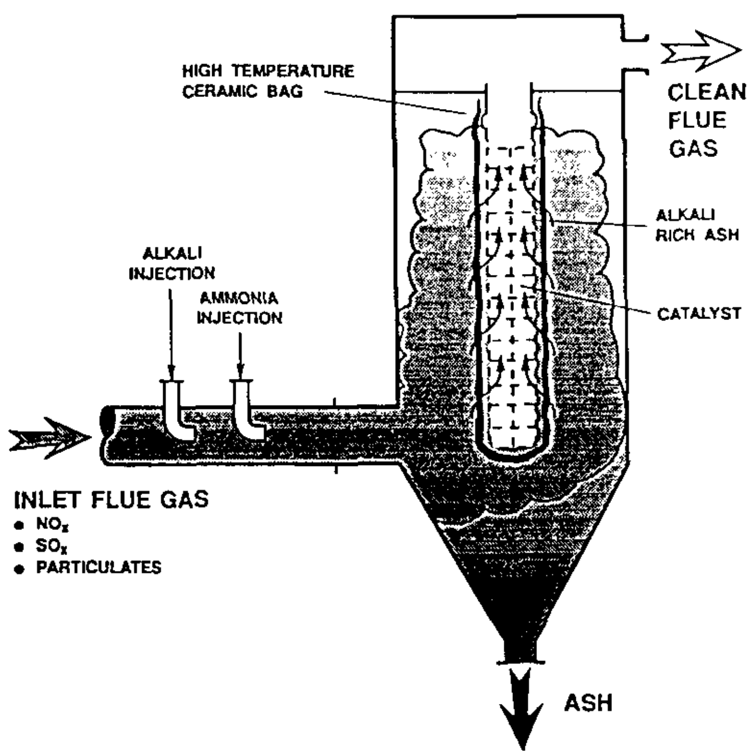


Figure 1 - SNRB Process

The selection of either a calcium- or sodium-based sorbent impacts the optimum operating temperature and, therefore, the arrangement of the system relative to the boiler. A schematic representation of one proposed commercial arrangement of the SNRB process is depicted in Figure 2. In this version, which features a calcium-based sorbent, commercial hydrated lime is injected into the convection pass of a boiler upstream of the economizer, where the flue gas temperature may range from 900° to 1100°F. Simultaneous dehydration and sulfation of the sorbent begins immediately upon injection and continues as the flue gas passes through the economizer and fluework and into the baghouse. The reaction products ($CaSO_3$, $CaSO_4$, and $CaCO_3$) along with the fly ash and unreacted sorbent are collected as a filter cake on the high-temperature

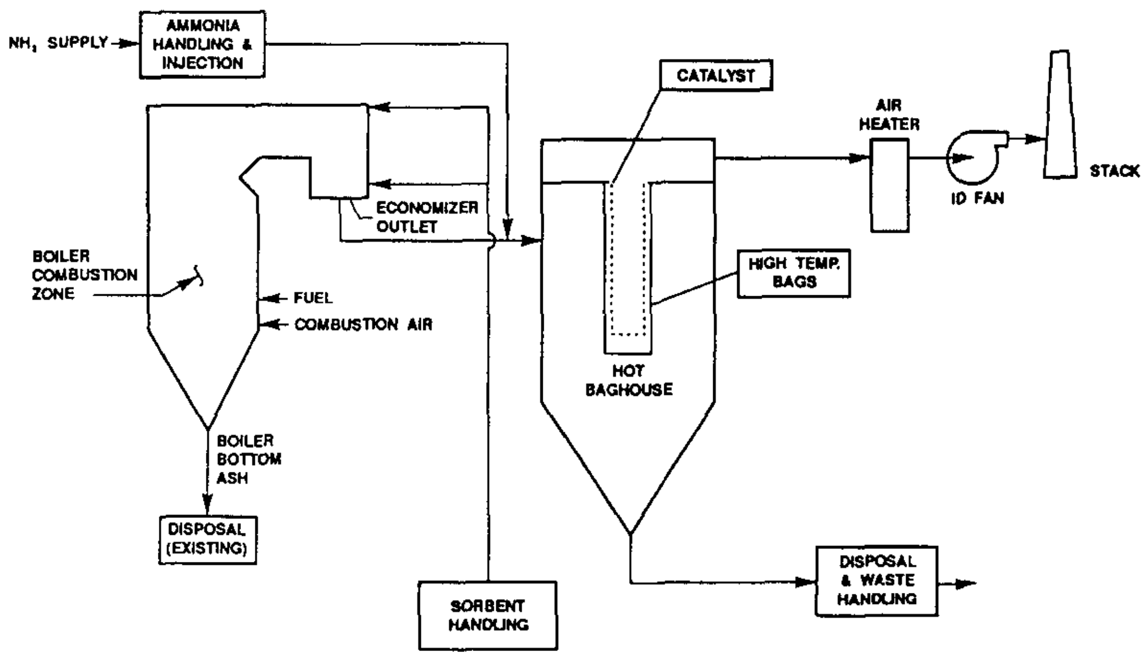


**Figure 2 - Potential Calcium-Based SNRB Process Schematic**

fabric filters in the baghouse. The baghouse operates in the temperature range of 700° - 850°F and, therefore, employs high-temperature ceramic or fiberglass bags. $SO_2$ reacts with the hydrated lime within a second of sorbent injection into the fluework and continues to react as the flue gas passes through the filter cake collected on the bags. By the time the flue gas reaches the baghouse, approximately 40 to 60% of the $SO_2$ may already be removed. Additional reaction occurs in the baghouse, yielding an overall $SO_2$ removal of at least 70%. The baghouse and fluework $SO_2$ removal split is dependent to some extent on the relative sorbent injection and baghouse operating temperatures.

For western U.S. utility applications, a sodium-based sorbent such as sodium bicarbonate ($NaHCO_3$) may be preferred due to its economic availability. $NaHCO_3$ sorbent requires injection downstream of the economizer, at a lower temperature range of 450° - 750°F. At higher temperatures, sintering of the $NaHCO_3$ may occur, thereby reducing the available surface area for reaction. The primary reaction products for $NaHCO_3$ injection include sodium sulfite ($Na_2SO_3$) and sulfate ($Na_2SO_4$).

The SCR catalyst may require reformulation for the sodium-based system in order to achieve optimal $NO_x$ reduction at these lower temperatures.

The SNRB process utilizes selective catalytic reduction (SCR) for high efficiency, post-combustion $NO_x$ control. In the presence of the SCR catalyst, $NO_x$ reacts with $NH_3$ to form $N_2$ and $H_2O$. A vanadium-free variant of the commercial NC-300™ series zeolite catalyst from Norton Chemical Process Products is being used in the SNRB CCT project. The SNRB process has been designed to avoid common operating problems encountered in the application of vanadium-based SCR catalysts to power plant emissions. These operating problems include: (1) catalyst deactivation by adsorption of heavy metals in fly ash and sulfur species in the flue gas; (2) ammonium bisulfate formation and subsequent deposition on steel surfaces; (3) catalytic oxidation of $SO_2$ to $SO_3$ and increased equipment corrosion due to the $SO_3$ generation; and (4) erosion or pluggage of the catalyst by fly ash [2]. These problems have been avoided in the SNRB process through the use of a non-toxic, zeolitic SCR catalyst and incorporation of the catalyst into each bag filter assembly, downstream of both $SO_x$ and particulate removal. By the time the flue gas reaches the catalyst, the $SO_2$ concentrations have been reduced by more than 70%, $SO_3$ concentrations have been reduced to below detectable levels, and particulates have been reduced to trace levels. $NO_x$ removal upstream of the combustion air preheater eliminates the need for a flue gas reheat system to provide the appropriate gas temperature for optimal $NO_x$ reduction.

A pulse-jet baghouse provides for high efficiency particulate removal. The pulse-jet design permits filtration at the high flue gas volumetric flow rates associated with high-temperature operation without requiring a large baghouse plan area.

An additional, potential benefit of SNRB is that the boiler's combustion air preheater can be operated at lower flue gas outlet temperatures. The removal of $SO_3$ through reaction with the injected alkali sorbent results in a lower flue gas acid dew point. This allows for added heat recovery from the flue gas through operation of the combustion air preheater at lower outlet temperatures without leading to increased corrosion. This increase in energy recovery could improve boiler efficiency by 1 to 3%, making the SNRB process one of few $SO_x/NO_x$ removal processes that could increase -- rather than decrease -- a power plant's net thermal efficiency. The extent to which heat recovery can be economically improved by upgrading the air preheater will be evaluated in an engineering study in Phase 3 of the SNRB CCT project.

## TECHNOLOGY DEVELOPMENT HISTORY

Development of the SNRB process at B&W actually began in the 1960's with internally sponsored programs which demonstrated the technical feasibility of dry sorbent injection for $SO_2$ removal at elevated temperatures upstream of a baghouse. Various means of incorporating $NO_x$ control into a combined process were evaluated in several pilot programs in the 1970's and 1980's. These pilot tests assessed various $NO_x$ reduction catalysts, integration of the $NO_x$ reduction catalyst with the baghouse, and evaluation of sodium- and calcium- based sorbents for $SO_2$ control. These early pilot tests demonstrated that performance on the order of 90% $SO_x$ and 60% $NO_x$ emissions reduction could be achieved with a sodium-based reagent. However, some work remained in evaluating techniques for regeneration of the sodium based reagents for applications in the Eastern United States and improvement of the $NO_x$

reduction efficiency. Internal reagent regeneration studies were supplemented by B&W, and OCDO co-sponsored pilot-scale work to demonstrate SNRB performance with calcium-based $SO_2$ sorbents. These pilot tests served to refine the design for integrating the SCR catalyst into the baghouse design and evaluate filter bag cleaning in an integrated system. These pilot tests demonstrated that $SO_x$ and $NO_x$ emission reductions of up to 85% could be simultaneously achieved with hydrated lime injection while maintaining low particulate emissions in an integrated system [1].

Norton evaluated and confirmed the compatibility of the zeolitic SCR catalyst with the SNRB process through a series of bench-scale reactor tests. The bench-scale tests emphasized the effects of $NH_3/NO_x$ stoichiometry, catalyst temperature and catalyst space velocity on $NO_x$ reduction, and ammonia slip. The $NH_3/NO_x$ stoichiometry is defined as the ratio of the moles of $NH_3$ injected to the moles of $NO_x$ in the flue gas. Space velocity refers to the gas flow rate per unit volume of catalyst. Ammonia slip refers to the amount of unreacted ammonia passing through the catalyst and exiting in the effluent. The Norton bench-scale results were used to guide the Phase 1 laboratory pilot testing and were used for comparison of the $NO_x$ removal efficiencies achieved in the pilot.

The feasibility of increasing calcium-based sorbent utilization through recycling partially reacted sorbent in the SNRB process was investigated in a series of bench-scale experiments. The experiments were conducted at the Advanced Fossil Fuel Research Institute at the University of Cincinnati. SNRB baghouse solid samples from the pilot testing were used in the sorbent recycling tests. The bench-scale tests indicated that simple sorbent recycling would not increase hydrated lime utilization. Due to the formation of a highly carbonated outer shell, the sorbent cannot be effectively recycled without thermal treatment. The effect of injection temperature on the competing carbonation/sulfation reactions continues to be investigated.

Additional pilot-scale demonstration of commercial sized bag/catalyst components was completed in Phase 1 of the current CCT demonstration project. As a technology utilizing a single major component, the high-temperature baghouse, the temperature compatibility of the $SO_2$ and $NO_x$ removal mechanisms is crucial to the success of the SNRB technology. One of the major objectives of the laboratory pilot test program was the confirmation of the baghouse/catalyst operating temperature range which yielded optimum $NO_x$ and $SO_2$ emission control. The SCR catalyst operating temperature range that maximized $NO_x$ removal performance, beyond which a loss in catalytic activity occurs, was established in the laboratory pilot testing. Likewise, the baghouse operating temperature yielding optimum $SO_2$ removal, beyond which sorbent sintering was a concern, was determined. Over the catalyst/bag temperature range of 800-850°F, greater than 70% $SO_2$ and 90% $NO_x$ reductions were achieved as illustrated in Figure 3.

These pilot tests also provided information on the effects of residence time/temperature profiles on $SO_2$ removal and air-to-cloth ratio on $NO_x$ and particulate removal efficiencies [2]. The air-to-cloth ratio is defined as the ratio of the flue gas volumetric flow rate to the filter fabric surface area in the baghouse. This pilot activity helped finalize the selection of the catalyst arrangement, sorbent injection configuration, and filter bag construction for the 5-MWe demonstration facility.

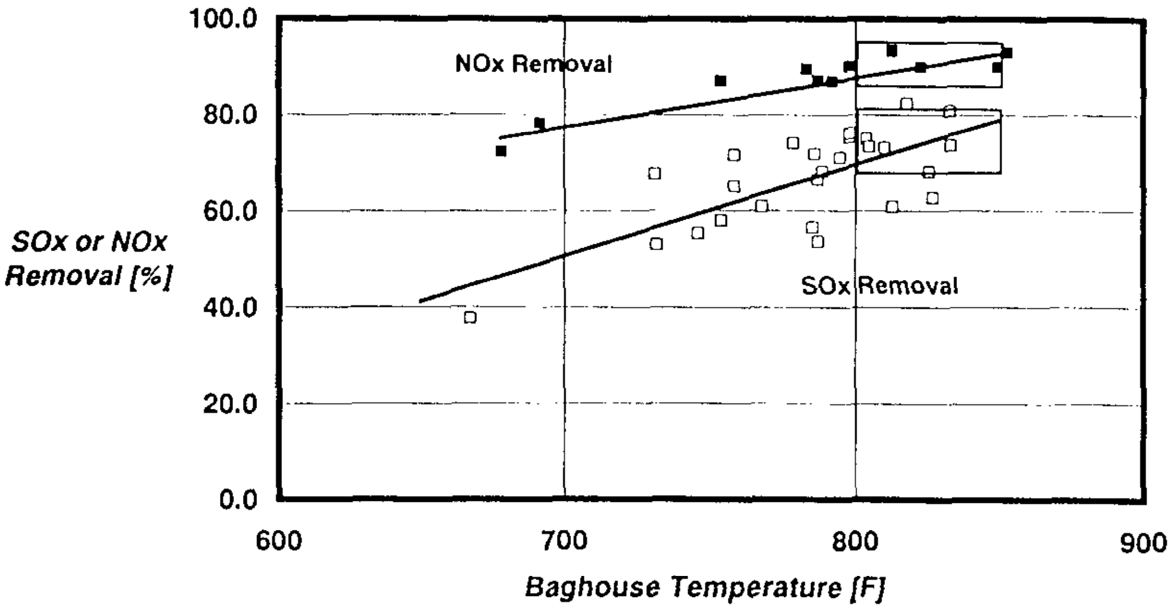


**Figure 3 - Pilot Verification of $SO_2$ and $NO_x$ Reduction Compatibility**

The 5-MWe demonstration is an integral step in the commercial development of the SNRB technology. This intermediate scale demonstration will provide the required operating experience with commercial scale components necessary to proceed to a larger application.

## DEMONSTRATION FACILITY DESCRIPTION

The major components of the 5-MWe SNRB demonstration facility are illustrated in Figure 4. A 23,000 ACFM flue gas slipstream from Ohio Edison's R. E. Burger Plant Boiler No. 8 economizer outlet hopper provides the flue gas source for the demonstration facility. To elevate the gas temperature from 650°F to the desired temperature window for injection of calcium- or sodium-based sorbents, the flue work system is equipped with a propane-fired burner. This burner will permit evaluation of sorbent injection temperatures up to 1200°F. The flue gas is then cooled to the desired baghouse operating temperature as it passes through an air-air, plate-type heat exchanger. The metal surface temperatures, gas residence time, and flue gas quench rate of this heat exchanger were designed to simulate those encountered in boiler economizer sections.

An ammonia/air mixture supplied by a packaged ammonia injection system is injected upstream of the hot catalytic baghouse. The sorbent feed system consists of a storage silo for the fresh sorbent, a weigh-type feeder to accurately meter the sorbent feed rate, and a pneumatic transport system to convey the sorbent to one of five injection locations in the flue work. Four of the injection ports are located in the high-temperature, refractory-lined flue work between the propane-fired burner and the inlet gas cooler, while the fifth is located

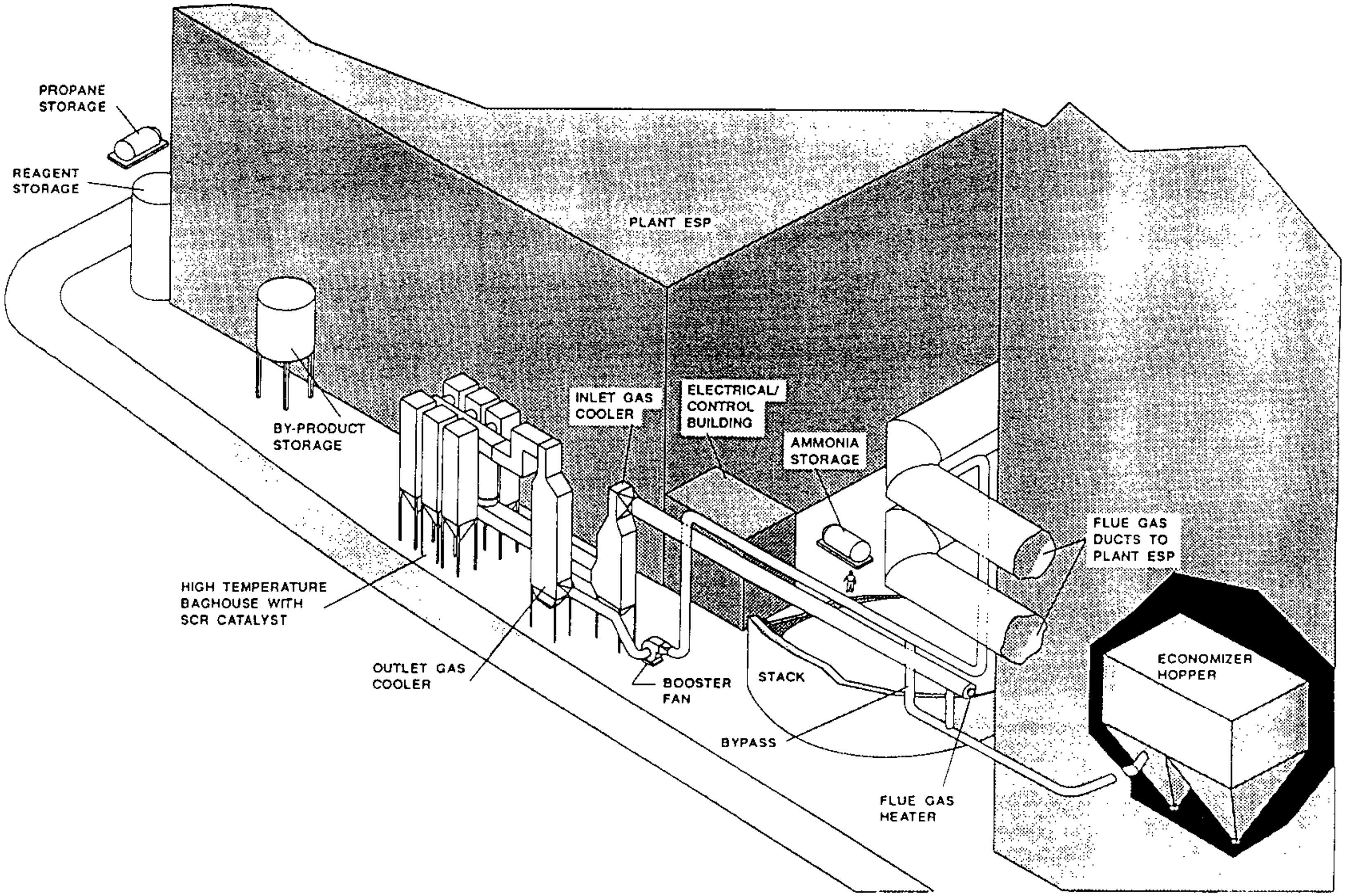


**Figure 4 - 5-MWe SNRB Demonstration Facility - R. E. Burger Plant, Ohio Edison**

between the inlet gas cooler and the baghouse. These multiple injection locations will provide the necessary flexibility to evaluate a wide range of residence time/temperature profiles during the testing program.

The baghouse has been designed for operating gas temperatures up to 900°F. The baghouse consists of six modules arranged in a three-by-two array. The hot flue gas entering the baghouse is distributed to the bottom of each of the six modules through a tapered inlet manifold. Manually operated butterfly dampers are used for module inlet isolation. The clean gas exits each module at the top and is collected in a tapered clean gas manifold. Pneumatically operated poppet valves are utilized for module outlet isolation. A bypass manifold, containing a pneumatically operated poppet valve, connects the inlet and outlet gas manifolds to automatically protect the baghouse in the event of a system upset.

The pulse-jet cleaning system is designed to permit either on-line or off-line cleaning in either manual or automatic operating modes. For additional flexibility during testing, in the automatic mode the fully adjustable cleaning cycle may be initiated on either a baghouse pressure differential, timed, or combined pressure differential/timed basis. Based on the results of the pilot-scale test discussed earlier, adequate cleaning should result with the use of 30-40 psig cleaning air pressure. However, the large 2-1/2 inch diaphragm valves, oversized air manifolds, and the availability of up to 100 psig cleaning air provide flexibility for significant variation of the cleaning air pulse.

The baghouse was sized for a nominal air-to-cloth ratio of 4:1 at a gas flow of 30,000 ACFM at a gas temperature of 800°F. Each of the six modules contains 42 full-size, integrated bag/catalyst assemblies. The Nextel™ style 312 woven, ceramic filter bags are similar to those used in the pilot-scale baghouse (20 feet long by 6-1/8 inches in diameter). An unpromoted version of Norton's commercial NC-300™ type SCR catalyst has been integrated into each of the 252 filter elements contained in the baghouse.

The baghouse modules are fitted with removable clean gas plenums to facilitate installation, inspection, and replacement of the bag/catalyst assemblies. A weatherproof enclosure covers the entire roof area of the baghouse system, and is equipped with a hoist/monorail system to assist in handling of the module clean air plenums and bag/catalyst assemblies.

The baghouse is equipped with a pneumatic ash removal system that transports the fly ash and SNRB process by-products to a storage silo. The ash storage silo is equipped for truck loading operation. The fly ash will be disposed of off-site at an approved solid waste landfill.

After exiting the baghouse, the flue gas is cooled further as it passes through a second air-air, plate-type heat exchanger. This outlet gas cooler has been designed to permit evaluation of the corrosive effects of $SO_3$ concentrations in the exit flue gas stream at temperatures as low as 170°F. This feature will permit evaluation of the potential for improved boiler efficiency through additional heat recovery at the combustion air preheater. Finally, the flue gas passes through the system booster fan before it is introduced into the existing Boiler No. 8 electrostatic precipitator inlet flue.

## PROJECT SCHEDULE

Key milestones in performance of the project are summarized in Table 1.

**TABLE 1**
**Project Schedule Milestones**

| | |
|---|---|
| Cooperative Agreement Signed | December, 1989 |
| Pilot Testing Completed | February, 1991 |
| Demonstration Construction | April - October, 1991 |
| Filter Fabric Test Start-up | November, 1991 |
| Demonstration Start-up | February - May, 1992 |
| Technology Transfer Open House | August, 1992 |
| Scheduled Field Test Completion | November, 1992 |
| Scheduled Project Completion | April, 1993 |

The start of the Phase 3 test program was delayed approximately three months from the original project schedule as a result of mechanical difficulties encountered in this first-of-a-kind demonstration. Currently, approximately half of the planned Phase 3 test program has been completed. The remaining testing is expected to be completed this fall. Additional, ongoing Phase 3 activity includes environmental assessment reporting, engineering and economic analyses, and planning for restoration of the Ohio Edison site. The project remains on schedule for completion in April, 1993. Completion of the project may be delayed to incorporate a proposed air toxics emissions control test program.

## FIELD DEMONSTRATION TEST OBJECTIVES

The primary goal of the SNRB field demonstration tests is to demonstrate high $SO_2$, $NO_x$, and particulate removal efficiencies during extended operation on fully-integrated, commercial-size components. The test program has been designed to determine the influence of key operating parameters on $SO_2$, $NO_x$, and particulate removal. Alternative hydrated lime sorbents, in addition to commercial hydrated lime, will be evaluated to determine the influence of sorbent selection on $SO_2$ removal optimization. Verification testing of SNRB process performance by an independent test agency for quality assurance will be included.

Planned operation of the demonstration facility is designed to address the following objectives:

- Meet emission reduction goals.
- Optimize $SO_2$ and $NO_x$ reduction efficiency.
- Develop system performance curves over a range of operating conditions.
- Evaluate commercial size catalyst/filter bag arrangement.
- Characterize alternative filter fabric performance and physical characteristics.

- Characterize the observed baghouse pressure drop.
- Examine catalyst deactivation over time.
- Evaluate the process control system approach.
- Characterize the solid by-product stream.

**INITIAL DEMONSTRATION TEST RESULTS**

Test activity was initiated at the SNRB demonstration facility in mid-May, 1992. The facility has been operated two to three weeks per month on a 24 hour/day, 5 day/week basis. The preliminary results presented here reflect the optimum overall performance to date in the first few months of operation of the facility. A significant amount of data analysis and performance optimization remains to be completed in the ongoing test program.

As of the end of July, approximately 700 hours of operation at baghouse temperatures of 750 to 850°F had been attained. Commercial grade hydrated lime supplied by Dravo Black River lime plant has been used as the $SO_2$ sorbent in all of the testing to date. Lime injection temperatures of 800 to 1100°F have been evaluated. The baghouse has been operated over a 700 to 900°F temperature range at air-to-cloth ratios of 3 to 4 with most of the testing being completed at an air-to-cloth ratio of 4.

$SO_2$ Removal

The overall $SO_2$ removal performance is affected by sorbent characteristics and operating conditions, such as injection temperature, residence time, baghouse operating temperature, and Ca/S stoichiometry. Parametric evaluation of these key parameters is being conducted at the demonstration facility. Most of the testing to date has been performed at a Ca/S stoichiometry of 2. The system inlet $SO_2$ concentration has ranged from 2000 to 3000 ppm.

For a fixed reagent stoichiometry, testing performed to date suggests the sorbent injection and baghouse operating temperatures have the most influence on $SO_2$ removal. These temperature effects are illustrated in Figure 5 for operation at a Ca/S stoichiometry of approximately 2.

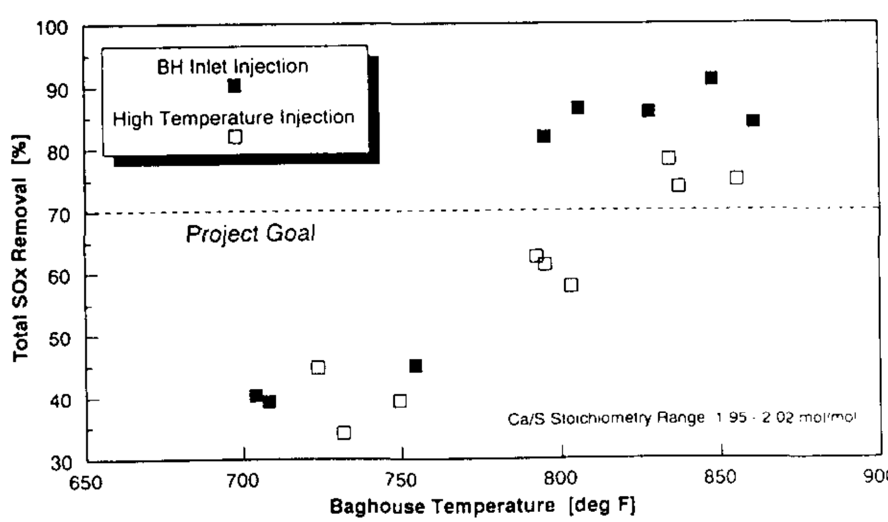


**Figure 5 - Effect of Operating Temperature on $SO_2$ Removal**

Higher removal efficiencies are observed when the hydrated lime is injected near the baghouse inlet at approximately 900°F rather than at 1000 to 1100°F further upstream of the baghouse. Bench-scale testing suggests this observation may reflect operation at lower temperature conditions which are less favorable for the $Ca(OH)_2$ carbonation reaction resulting in a higher availability of $Ca(OH)_2$ for reaction with $SO_2$ in the baghouse. Optimization of the sorbent injection location and temperature will continue as the testing proceeds.

## $NO_x$ Reduction

$NO_x$ reduction performance is primarily influenced by the $NH_3/NO_x$ stoichiometry and the catalyst temperature. Minimizing the $NH_3/NO_x$ ratio while meeting the required $NO_x$ reduction helps to reduce operating costs and minimize the concentration of ammonia in the exiting flue gas which is referred to as ammonia slip. Measurements over a 0.65 to 0.90 $NH_3/NO_x$ operating range indicate the ammonia slip has been less than 10 ppm with a majority of the measurements below 5 ppm.

The effect of catalyst (baghouse operating) temperature on $NO_x$ removal is illustrated in Figure 5. The data shown in Figure 6 was obtained at an $NH_3/NO_x$ stoichiometry of 0.8.

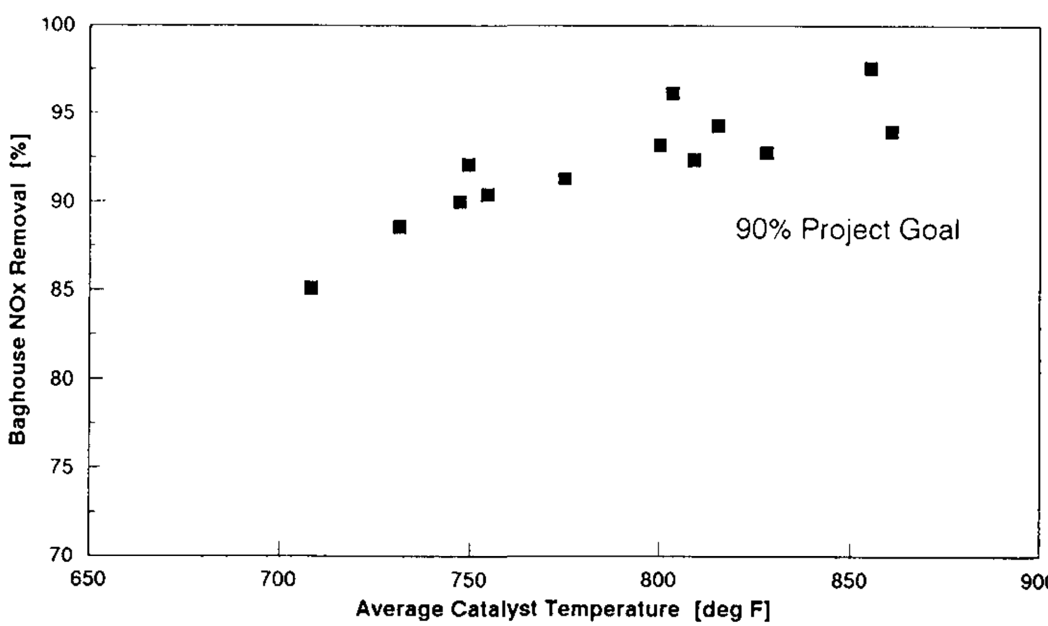


**Figure 6 - Effect of Catalyst Temperature on $NO_x$ Removal**

These $NO_x$ removal measurements reflect total $NO_x$ reduction from the inlet to the outlet of the baghouse. This includes the baseline $NO_x$ reduction across the baghouse observed at temperature, but without ammonia injection. Some $NO_x$ reduction is believed to result from reaction with the fly ash on the filter bags and the steel surfaces of the filter bag retainers and catalyst holders at the elevated baghouse operating temperatures.

Testing continues at the demonstration facility to further quantify baseline $NO_x$ reduction with and without ammonia injection and with the catalyst removed. The ammonia flow rate measurement will also be re-examined to verify the $NH_3/NO_x$ stoichiometry calculations.

Particulate Collection

SNRB process particulate emissions are influenced by the bag cleaning technique (on-line vs. off-line), the baghouse pressure drop, cleaning frequency, and the cleaning air pulse pressure. The air-to-cloth ratio and Ca/S stoichiometric ratio may also affect emissions. Operation of the facility to date has primarily involved on-line bag cleaning with 30 to 40 psig cleaning air pressure. Module cleaning frequency has averaged approximately 3 to 4 hours at an air-to-cloth ratio of 4.

Particulate emissions are measured periodically using an EPA Method 5 sample train. A continuous opacity monitor provides a qualitative indication of particulate emissions. The system outlet opacity is consistently less than 5%, although brief spikes above 5% are observed during bag cleaning. Approximately 20 baghouse outlet particulate loading measurements have been completed to date. The mass loadings have ranged from 0.004 to 0.019 lb/million Btu. The average of the mass loadings measured with hydrated lime injection is 0.012 lb/million Btu. These measurements include the impact of particulate penetration which results from on-line bag cleaning. The particulate emissions are well below the 0.03 lb/million Btu New Source Performance Standard.

**MARKET POTENTIAL**

The potential commercial applications of SNRB for controlling emissions from coal-fired boilers include Clean Air Act Phase II compliance retrofit installations, new coal-fired electric generating capacity, and industrial applications. In addition to marketing as a combined $SO_x$, $NO_x$, and particulate emissions control technology, two other marketing thrusts may be applied -- primarily $SO_2$ control or primarily $NO_x$ and particulate emissions control. SNRB is an excellent choice for high efficiency $NO_x$ and particulate emissions control where $SO_2$ control may be of secondary importance.

Approximately 102,000 MWe of existing generating capacity will require new or additional $SO_2$ reduction capability to meet the CAA Phase II emission limits. For compliance with Phase I, approximately 21% of the total generating capacity $SO_2$ emission reductions will be achieved by wet scrubbing and 53% through fuel switching or blending to meet the general base limit of 2.5 lb/$10^6$ Btu limit. Current projections suggest a Phase II $SO_2$ emission control market for advanced clean coal technologies such as SNRB of 10,000 to 20,000 MWe. The impact of pending $NO_x$ emission reduction requirements, particularly in ozone non-attainment areas, will also affect the potential market for SNRB applications. As has been demonstrated, SNRB is capable of achieving 90% $NO_x$ emission reduction.

In addition to pending $NO_x$ emission limits, the SNRB retrofit market will be influenced by factors such as current $SO_2$ and $NO_x$ emission levels, unit age and planned service life, combustion technology, contribution to the utility system's generating capacity, and the location of the unit. Near term, potential SNRB retrofit applications are expected to include units without "low-$NO_x$" modifications or FGD systems, units built after 1960, and units emitting more than 1.1 lb/$10^6$ Btu $NO_x$. Also, units experiencing particulate emission control problems and requiring additional $SO_2$ or $NO_x$ control would be suitable for SNRB.

Approximately 10,000 to 20,000 MWe of new generating capacity is anticipated to be installed by the year 2000. Much of this additional capacity will come from smaller, independent power producers as opposed to the traditional utility market. A combined, flexible, high efficiency emission control process such as SNRB would be suitable for these smaller, multiple fuel operations.

The low space requirements, operating flexibility, and multiple pollutant control features of SNRB make it especially attractive for industrial applications.

The rate of SNRB participation in the Phase 2 retrofit emission control market will be accelerated if a suitable next step demonstration can be completed in the near term. Babcock & Wilcox continues to search for potential SNRB first commercial applications in the utility and industrial markets.

## SUMMARY

Preliminary results from the 5-MWe demonstration facility indicate emission reduction performance in excess of the initial project goals of 70% $SO_2$ removal, 90% $NO_x$ reduction and NSPS particulate emissions compliance. To date, $SO_2$ emission reductions of up to 85% have been observed at a Ca/S ratio of 2 and baghouse operating temperature of 850°F. Greater than 90% $NO_x$ reduction has been obtained at an $NH_3/NO_x$ ratio of 0.9. Particulate emissions at the baghouse outlet have consistently been less than 0.03 $lb/10^6$ Btu.

To date, the results and operating experience at the 5-MWe SNRB demonstration facility have been encouraging. High emission control efficiencies have been achieved for $SO_2$, $NO_x$, and particulates. Plant engineering integration, economic evaluation, and market assessment activity remains to be completed in the current CCT project. The challenge for the project team now is to move the technology through the next phase of commercial development to a larger industrial or utility application.

Future testing will focus on assessment of alternative bag filter fabrics and optimization of $SO_2$ removal performance. These two areas appear to present the greatest opportunity for reducing operating and capital costs associated with the SNRB technology.


## ACKNOWLEDGMENTS

The authors express their appreciation to the U.S. Department of Energy (DOE), the Ohio Coal Development Office (OCDO), and the Electric Power Research Institute (EPRI) for supporting the SNRB Flue Gas Cleanup Project. Additional thanks are due to Ohio Edison for their support of the 5-MWe Field Demonstration, and the City of Colorado Springs Utilities for supporting the filter fabric durability assessment pilot facility. The technical support and assistance of 3M and Norton is greatly appreciated.

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# THE NOXSO CLEAN COAL TECHNOLOGY PROJECT: A 115 MW DEMONSTRATION UNIT

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## ABSTRACT

The NOXSO Clean Coal Technology Project is a 115 MW demonstration unit to be located at Ohio Edison's Niles Plant. The NOXSO process is a dry, post-combustion flue gas treatment technology which uses a regenerable sorbent to simultaneously adsorb sulfur dioxide ($SO_2$) and nitrogen oxides ($NO_x$) from the flue gas of a coal-fired utility boiler. In the process, the $SO_2$ is reduced to elemental sulfur and the $NO_x$ is reduced to nitrogen and oxygen. It is predicted that the process can economically remove 90% of the acid rain precursor gases from the flue gas stream in a retrofit or new facility. The project is co-funded by the U.S. Department of Energy (DOE) and a consortium of organizations assembled by NOXSO including NOXSO Corporation, W.R. Grace & Co.-Conn., Ohio Edison, the Ohio Coal Development Office (OCDO) of the Ohio Department of Development, the Electric Power Research Institute (EPRI), the Gas Research Institute (GRI), and the East Ohio Gas Company. The DOE manages the project through the Pittsburgh Energy Technology Center (PETC). Both the NOXSO Process and its

application to the Niles Plant are described in this paper. The status of the NOXSO Proof-of-Concept pilot plant located at Ohio Edison's Toronto Plant is updated, and its impact on the Niles Demonstration Plant design is described. Finally, results of the $NO_x$ recycle test programs are discussed.

## INTRODUCTION

The NOXSO Process is a dry, post-combustion flue gas treatment technology which uses a regenerable sorbent to simultaneously adsorb sulfur dioxide ($SO_2$) and nitrogen oxides ($NO_x$) from the flue gas of a coal-fired utility boiler. In the process, the $SO_2$ is reduced to elemental sulfur and the $NO_x$ is reduced to nitrogen and oxygen. It is predicted that the process can economically remove 90% of the acid rain precursor gases from the flue gas stream in a retrofit or new facility.

Process development began in 1979 starting with laboratory scale tests and progressing to pre-pilot scale tests (3/4-MW) and a life cycle test. Each of these test programs [1,2,3] have provided data necessary for the process design. Tests of the $NO_x$ recycle concept which is inherent to the NOXSO Process have been conducted on small boilers at PETC and the Babcock & Wilcox (B&W) Research Center in Alliance, Ohio. A 5 MW Proof-of-Concept (POC) pilot plant at Ohio Edison's Toronto Plant in Toronto, Ohio is currently operating. The 115 MW full-scale demonstration plant to be built at Ohio Edison's Niles Plant near Warren, Ohio is currently being designed.

The 115 MW Demonstration Project will be cost shared between the Department of Energy through the third round of the Clean Coal Technology program by a cooperative agreement between DOE and NOXSO. The cooperative agreement is currently being assigned (novated) to NOXSO by MK-Ferguson and will be formally executed shortly. The team assembled by NOXSO to fund and execute the project is shown in Figure 1. DOE will provide 50% of the funds necessary to design, build and operate the plant while the remaining 50% will be provided by NOXSO, Grace, Ohio Edison, OCDO, EPRI, GRI and the East Ohio Gas Company. DOE will manage the demonstration project through the Pittsburgh Energy Technology Center (PETC).

Project execution will be conducted by NOXSO, Grace, Ohio Edison and MK-Ferguson, with specific responsibilities as indicated in Figure 1. In this paper, we describe the NOXSO Process as it will be implemented at Ohio Edison's Niles Plant and the current schedule for design, construction and operation of the 115 MW facility. We also describe the test programs being conducted at the POC pilot plant that will provide the final design and scale-up data necessary for the Niles Plant. Also, $NO_x$ recycle data obtained during the pre-pilot scale and the B&W $NO_x$ recycle tests are described.

## HOST SITE DESCRIPTION

The Niles Plant is located on the Mahoning River in northeastern Ohio and is shown in Figure 2. It has a net demonstrated power production capability of 246 MW. Two coal-fired units produce 108 MW net each (115 MW gross each) and 30 net MW is obtained from a combustion turbine which is used for peaking purposes. At full load, the plant fires 97 tons of bituminous coal per hour. The average annual coal quality analysis for 1991 is shown in Table 1. Of all the coal received at the Niles Plant, 60 percent is typically Ohio coal and 40 percent is non-Ohio (western Pennsylvania).

Both process and cooling water are drawn from the Mahoning River at a rate of 140,550,000 gallons per day. Ample water supply is available for the NOXSO Process requirements which amount to approximately 100,000 gallons per day. NOXSO net electricity requirements will be provided by the Niles plant and are estimated to be about 3.4% (or 3.9 MW) of the gross power output of Unit #1.

## NOXSO PROCESS DESCRIPTION

The NOXSO demonstration plant will be retrofitted to Niles Unit #1, a crushed coal-fired cyclone boiler with a rating of 115 MW (gross) and 108 MW (net). The tie-in point will be the flue gas ductwork between the existing electrostatic precipitator (ESP) and the plant chimney. The NOXSO Process can operate either upstream or downstream of the particulate collection device; however, the current tie-in point was chosen to minimize the effect on ESP performance. The demonstration plant will occupy an area approximately 280 feet by 150 feet. A description of the process technology is given below and a process flow diagram is shown in Figure 3.

Flue gas from downstream of the Unit #1 ESP will be ducted to two flue gas booster fans. (Where multiple equipment is used, only one is shown in Figure 2 for simplicity.) Downstream of the booster fans, the flue gas is cooled by vaporizing a stream of water sprayed directly into the ductwork in order to maintain the adsorber inlet temperature at 300°F. After being cooled, the flue gas is passed through two parallel, two-stage, fluidized bed adsorbers where $SO_2$ and $NO_x$ are simultaneously removed using a high surface area $\gamma$-alumina sorbent impregnated with an alkali material. Tail gas from the sulfur plant is injected between the two adsorber stages to increase the ratio of $SO_2$:$NO_x$ and consequently increase $NO_x$ removal efficiency in the second (upper) bed. The cleaned flue gas passes through a cyclone separator and is returned to the plant ductwork and exits through the chimney. The cyclone returns entrained sorbent back to the adsorber.

Sorbent is removed from the adsorbers and transported by one of four dense-phase pneumatic conveyors to one of two disengaging vessels before it enters the sorbent heater. Fresh make-up sorbent is added downstream of the adsorbers so that it is calcined in the sorbent heater before making its first pass through the adsorbers. The sorbent heater is a variable area five-stage fluidized bed where a hot air stream is used to raise the sorbent temperature to 1150°F. During the heating process, $NO_x$ and loosely bound $SO_2$ are desorbed and transported away in the heating gas ($NO_x$ recycle) stream. This hot air stream is used to heat a slip stream of the power plant's main condensate before being injected into the combustion air system upstream of the combustion air preheater. The $NO_x$ recycle stream provides approximately 30% of the required combustion air. Upon entering the boiler, a portion of the recycled $NO_x$ is converted to nitrogen ($N_2$) and either carbon dioxide ($CO_2$) or water ($H_2O$) by reaction with free radicals in the reducing atmosphere of the combustion chamber. $NO_x$ recycle studies were performed during a previous NOXSO test program (a 3/4 MW pre-pilot scale test). More recently, $NO_x$ recycle studies were conducted using a scaled model cyclone boiler. These tests are discussed in more detail below.

Once the sorbent reaches a regeneration temperature of 1150°F, it is transported by means of two J-valves to a moving bed regenerator. In the regenerator, sorbent is contacted with natural gas in a countercurrent manner. The natural gas reduces sulfur compounds on the sorbent (mainly sodium sulfate) to primarily $SO_2$ and hydrogen sulfide ($H_2S$) with some carbonyl sulfide (COS) also formed. Approximately 20% of the sodium sulfate ($Na_2SO_4$) is reduced to sodium sulfide ($Na_2S$) which is subsequently hydrolyzed in a moving bed steam treatment reactor which follows the regenerator. A concentrated stream of $H_2S$ is obtained from the reaction of steam with $Na_2S$. The off-gases from the regenerator and steam treater are combined and sent to a sulfur plant which produces elemental sulfur. The tail gas stream from the sulfur plant is passed through an incinerator to convert all remaining sulfur compounds to $SO_2$, cooled to about 600°F, and recycled to the flue gas between adsorber stages.

From the steam treatment vessel, the sorbent is transported by means of two J-valves to the sorbent cooler. The cooler is a five-stage variable area fluidized bed using ambient air to cool the sorbent. The warm air exiting the cooler is further heated by a natural gas fired in-duct heater before being used to heat the sorbent in the fluidized bed sorbent heater. The sorbent temperature is reduced in the sorbent cooler to the adsorber temperature of 300°F. Sorbent from the sorbent cooler is transported by means of two J-valves to two surge tanks, one located above each adsorber. The surge tank is used as a source and sink for sorbent to maintain constant bed levels in the other process vessels. From the surge tank, sorbent flow to the adsorbers is regulated using L-valves, thus completing one full cycle.

## NILES DEMONSTRATION PLANT SCHEDULE

Much of the information required to design the full-scale demonstration plant is available from earlier NOXSO test programs. The POC pilot plant is supplying additional design data and scale-up information which is being used in preparing the preliminary design of the Niles demonstration plant. Although the preliminary design work on the Niles plant officially began in March of 1991, the level of effort was minimal until March of 1992 when the POC had been operating for several months generating performance data. The preliminary design will be completed in March of 1993, at which time the POC test program will be complete. Detailed design will be completed in October of 1993 at which time construction will begin. Shake down testing will begin in November of 1994. The operations period, which includes parametric, transient and long duration tests, will last for a period of 24 months continuing through February 1997. The schedule is summarized in Table 2.

## POC PILOT PLANT TEST PROGRAMS

The POC pilot plant began cold start-up in July of 1991. Cold start-up was the first of three test series. The second test series was a hot start-up with inert gases. The third test program is a set of parametric tests with the system fully operational, i.e., using flue gas in the adsorber and reactive (rather than inert) gases in the regenerator and is currently in progress. There are thirty parametric tests planned and the process parameters being varied are sorbent circulation rate, adsorber settled bed height, regenerator solids residence time and adsorber gas flow rate. The parametric tests will be followed by a duration test at optimum process conditions as determined by the parametric tests. The results from these tests will be incorporated in the detailed design of the NOXSO demonstration plant.

The first test program, cold start-up, was designed to verify the proper operation of each piece of equipment in the plant. After initial shakedown tests, sorbent was circulated through the system continuously for 43 hours. This test revealed the need to modify vessel internals in the staged fluid beds to achieve the maximum required sorbent circulation rates.

After the modifications were completed, a hot sorbent circulation test was performed for 38 continuous hours. The hot circulation test showed that the fluid bed residence time needed to be increased to achieve adequate heat transfer in the sorbent heater and sorbent cooler. After these additional modifications were completed, a second hot sorbent circulation test was initiated. During this test, gas tracer studies were conducted to verify isolation of gases between process vessels. Proper operation of the distributed control system trip matrix was also verified.

Flue gas was first processed in the pilot plant in November, 1991. Since that time, the plant has logged a total of over 2500 hours on flue gas. Parametric tests are ongoing and the complete set of results will be available in November 1992. Progress of the test program to date is summarized below:

- Average pollutant removal efficiencies at the pilot plant have been 90% $SO_2$ and 80% $NO_x$ at typical inlet $SO_2$ and $NO_x$ flue gas concentrations of 2000 ppm and 350 ppm, respectively. Removal efficiencies of 95% $SO_2$ and 92% $NO_x$ were measured at a sorbent circulation rate of 8050 pounds per hour (PPH), a flue gas flowrate of 5800 SCFM, and an adsorber bed temperature of 320°F.
- Measured sorbent attrition rates at the pilot plant have been lower than originally projected. The projected rate of sorbent makeup was 4.5 PPH based on data obtained from fluid beds in tests at smaller scale using previous sorbent grades. The actual rate measured over 1020 hours of operation at a constant set of operating conditions was 2.5 PPH. The measured rate was based on both the amount of sorbent makeup required to maintain steady system inventory and the amount of sorbent fines collected from the process off-gas streams in the baghouse. The sorbent used at the POC is being tested for the first time in a fully integrated NOXSO system. The low attrition rates and high internal surface area measurements indicate this sorbent is superior to previously tested sorbent grades.
- Mass and energy balances have been continuously monitored at the pilot plant. Mass and energy balance closures are required to verify the accuracy

of gas analyses, sorbent analyses, gas and sorbent flow rates, temperatures, etc. The sulfur balance between the adsorber and the regenerator, the $NO_x$ balance between the adsorber and the sorbent heater, and the carbon balance in and out of the regenerator all close to within $\pm 15\%$. The sorbent heater, air heater, and sorbent cooler energy balances are typically 85%, 98%, and 85% (with 100% equal to perfect closure).

A corrosion test program is being conducted during POC plant operation. Corrosion test spools containing material test samples are installed in seven different locations to assess corrosion rates in different gas and sorbent environments. Coupon weights and dimensions are measured before and after exposure, and these values are used to calculate corrosion rates of each material. Table 3 lists corrosion spool locations at the POC and the process components that will experience the same environment. Figure 4 is a photograph showing a corrosion test spool prior to installation at the pilot plant. The materials to be tested on each corrosion spool of coupons are listed below in Table 4.

The expected duration of the entire POC test program is about 20 months. In this relatively short period of time, it may be difficult to distinguish corrosion rates between some of the materials tested. Therefore, concurrently with the POC test program, there will be an accelerated corrosion test program conducted by an independent laboratory. The accelerated corrosion tests will consist of exposing corrosion coupon spools to simulated regenerator environments. A total of six tests will be conducted. The tests will be at three different temperatures and two different gas compositions. The reactor tube containing the corrosion test spool will also be packed with sulfated NOXSO sorbent to simulate the regenerator vessel environment. The test matrix is listed in Table 5. Each test condition will last for three weeks of continuous exposure. The results of these two corrosion test programs will be used to select materials of construction for the NOXSO demonstration plant.

## $NO_x$ RECYCLE TEST PROGRAMS

The $NO_x$ recycle concept cannot be tested at the pilot plant because the POC only uses a slipstream of flue gas equal to 1/12 of the plant's flue gas output. Since the $NO_x$ recycle stream is also 1/12 the size it would be for a full-scale NOXSO plant, dilution in the full flow combustion air stream would make any test data meaningless. However, simulated $NO_x$ recycle tests were conducted during the pre-pilot scale tests conducted at the DOE's Pittsburgh Energy Technology Center [2] and more recently at the B&W Research Center. The $NO_x$ recycle tests are conducted by injecting bottled $NO_x$ compounds into the combustion air in concentrations that reproduce the $NO_x$ concentration which will occur when the $NO_x$ recycle stream is mixed with the combustion air.

Tests at PETC were conducted using a pulverized coal burner and a tunnel furnace burning natural gas and a coal-water slurry. Approximately 65% of the $NO_x$ was destroyed in the PC burner while 75% was destroyed in the tunnel furnace.

$NO_x$ recycle tests were recently completed at the B&W Research Center using a small boiler simulator (SBS) which is a scaled cyclone boiler of the type used at Niles. A schematic of the B&W SBS is shown in Figure 5. $NO_x$ destruction was investigated as a function of furnace load, excess air, injection location (primary air, secondary air, or both simultaneously) and injected $NO_x$ concentration and specie (NO or $NO_2$). For conditions similar to those which will be encountered at Niles, the destruction efficiency is between 60 and 65%.

## SUMMARY

NOXSO Corporation's Clean Coal Technology project is a 115 MW demonstration of the NOXSO flue gas treatment process. The host site for the project is Ohio Edison's Niles Plant located on the Mahoning River in Niles, Ohio. Preliminary design for the demonstration unit is scheduled to be complete in early 1993 with detailed design being completed in late 1993. Plant construction should then be completed in late 1994 with full load operation beginning in early 1995. The project will be completed in February of 1997. Much of the necessary design data has been acquired through previous experimental test programs. The final design data will be obtained from NOXSO's POC pilot plant at Toronto, Ohio.

## REFERENCES


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2. Haslbeck, J.L., W.T. Ma, and L.G. Neal, "A Pilot-Scale Test of the NOXSO Flue Gas Treatment Process", U.S. Department of Energy Contract No. DE-FC22-85PC81503, June 1988.
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Figure 1. Project Organization Chart.

Figure 2. Ohio Edison's Niles Plant, Niles, Ohio.

Figure 3. NOXSO Process Flow Diagram.

Figure 4. Photograph of Corrosion Spool.

Figure 5. Babcock & Wilcox's Small Boiler Simulator (SBS) Schematic.

| | |
|---|---|
| Moisture (%) | 7.32 |
| Ash (%) | 11.72 |
| Sulfur | 2.79 |
| Heating Value (Btu/lb) | 11,810 |

**Table 1. Annual Coal Quality Analysis for the Niles Plant (1991)**

| | |
|---|---|
| Preliminary Design | April 1991 - March 1993 |
| Detail Design | March 1993 - October 1993 |
| Construction | October 1993 - February 1995 |
| Operation | February 1995 - February 1997 |

**Table 2. Project Schedule**

| Spool Location | Components |
|---|---|
| #1, Adsorber Inlet | Ductwork between spray cooler and adsorber, base of adsorber, and adsorber gas distributor. |
| #2, Adsorber Outlet (top of adsorber) | Adsorber (above distributor), adsorber cyclone, and ductwork between adsorber and stack. |
| #3, Air Heater Outlet | Air heater, duct between air heater and sorbent heater, bottom gas distributor in sorbent heater, and sorbent heater. |
| #4, Regenerator (gas space) | Regenerator, piping between regenerator and incinerator, and control valves on piping. |
| #5, Regenerator (sorbent bed) | Regenerator, sorbent transfer line from sorbent heater to regenerator, and transfer line from regenerator to steam treater. |
| #6, Steam Treater (gas space) | Steam treater, piping between steam treater and incinerator, and control valves on piping. |
| #7, Steam Treater (sorbent bed) | Steam treater, vessel surface in contact with sorbent. |

**Table 3. Location of POC Corrosion Test Spools and Process and Components Affected**

| Materials | Spool No. 1 | 2 | 3 | 4 | 5 | 6 | 7 | Accel-erated Tests |
|---|---|---|---|---|---|---|---|---|
| STAINLESS STEEL | | | | | | | | |
| 304 SS | X | X | X | X | X | X | X | X |
| 304H SS | | | X | X | X | X | X | X |
| 316 SS | X | X | X | X | X | X | X | X |
| 446 SS | X | X | X | X | X | X | X | X |
| 1010 CS | X | X | X | X | X | X | X | X |
| HASTELLOYS | | | | | | | | |
| C-276 | X | X | | | | | | |
| C-22 | X | X | | | | | | |
| C-4 | X | X | | | | | | |
| 304 SS (Alonized) | | | X | X | X | X | X | X |
| 304H SS (Alonized) | | | X | X | X | X | X | X |
| 316 SS (Alonized) | | | X | X | X | X | X | X |
| 1010 CS (Alonized) | | | X | X | X | X | X | X |
| 304 SS (Chromized) | | | X | X | X | X | X | X |
| 1010 CS (Chromized) | | | X | X | X | X | X | X |
| OVERLAYS | | | | | | | | |
| 304 SS with 556 SS | | | X | X | X | X | X | X |
| 304 HS with HR-160 | | | X | X | X | X | X | X |
| 304 SS with 446 SS | | | X | X | X | X | X | X |
| 304H SS with 446 SS | | | X | X | X | X | X | X |
| SPRAYCOAT, AFTER WELDS | | | | | | | | |
| Alonized 304 SS with 446 SS | | | X | X | X | X | X | X |
| Alonized 304H SS with 446 SS | | | X | X | X | X | X | X |
| 304 SS with 446 SS | | | X | X | X | X | X | X |
| 304H SS with 446 SS | | | X | X | X | X | X | X |
| Haynes 556 | X | X | | | | | | |
| Haynes HR-160 | X | X | | | | | | |
| Carpenter 20Cb3 | X | X | | | | | | |
| Jessop JS276 | X | X | | | | | | |
| Inco C-276 | X | X | | | | | | |
| Inco 625 | X | X | | | | | | |
| Teflon | X | X | | | | | | |

**Table 4. Materials to be Tested During the POC Corrosion Test Program**

| Test No. | Temp. (°F) | Gas Environment |
|---|---|---|
| 1 | 1200 | 40%CO, 40%$SO_2$, 10%$H_2O$, 10%$CH_4$ |
| 2 | 1400 | 40%CO, 40%$SO_2$, 10%$H_2O$, 10%$CH_4$ |
| 3 | 1600 | 40%CO, 40%$SO_2$, 10%$H_2O$, 10%$CH_4$ |
| 4 | 1200 | 50%$H_2S$, 50%$H_2O$ |
| 5 | 1400 | 50%$H_2S$, 50%$H_2O$ |
| 6 | 1600 | 50%$H_2S$, 50%$H_2O$ |

**Table 5. Accelerated Corrosion Test Conditions**

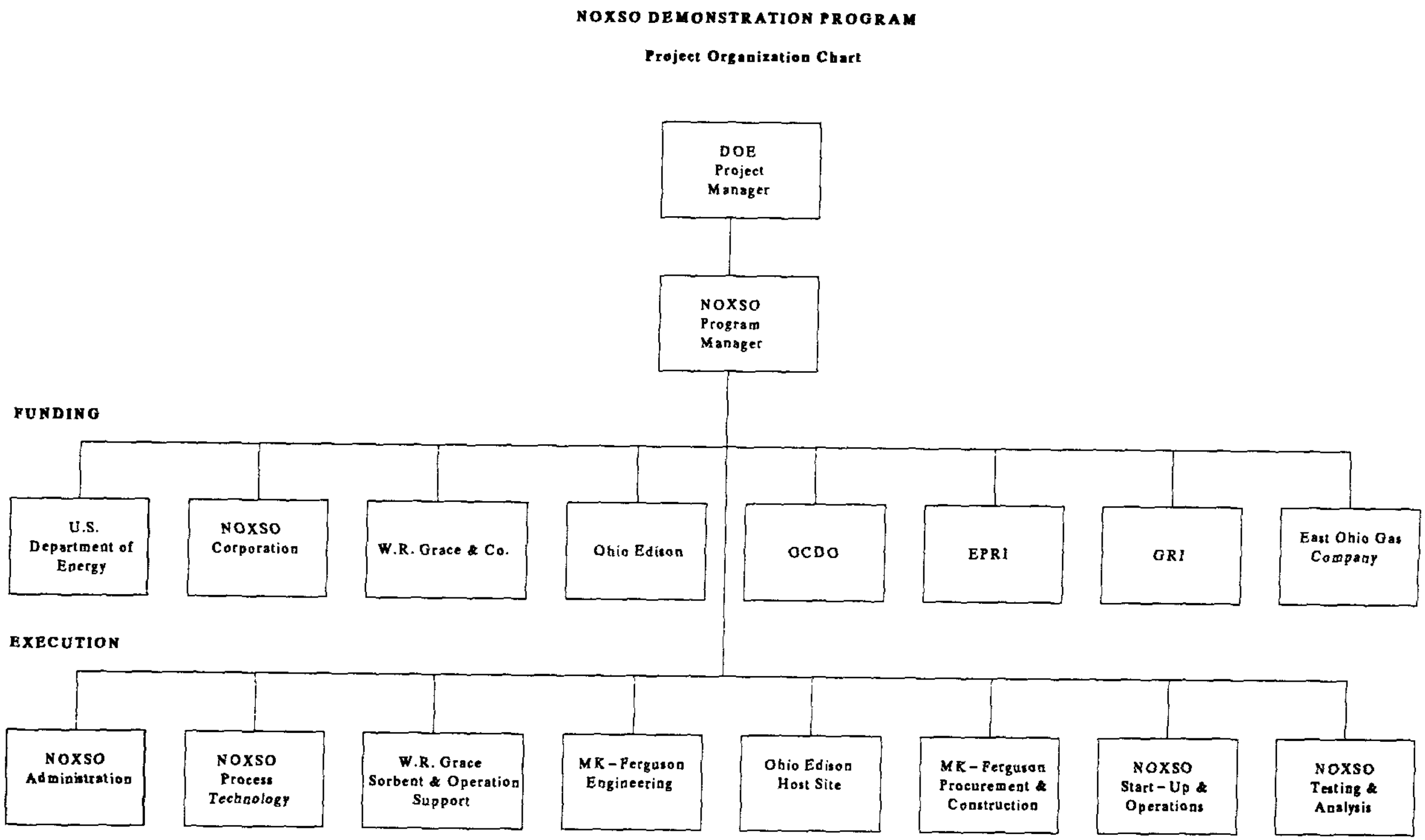


**Figure 1. NOXSO Demonstration Program**


**Figure 2. Ohio Edison's Niles Plant, Niles, Ohio**

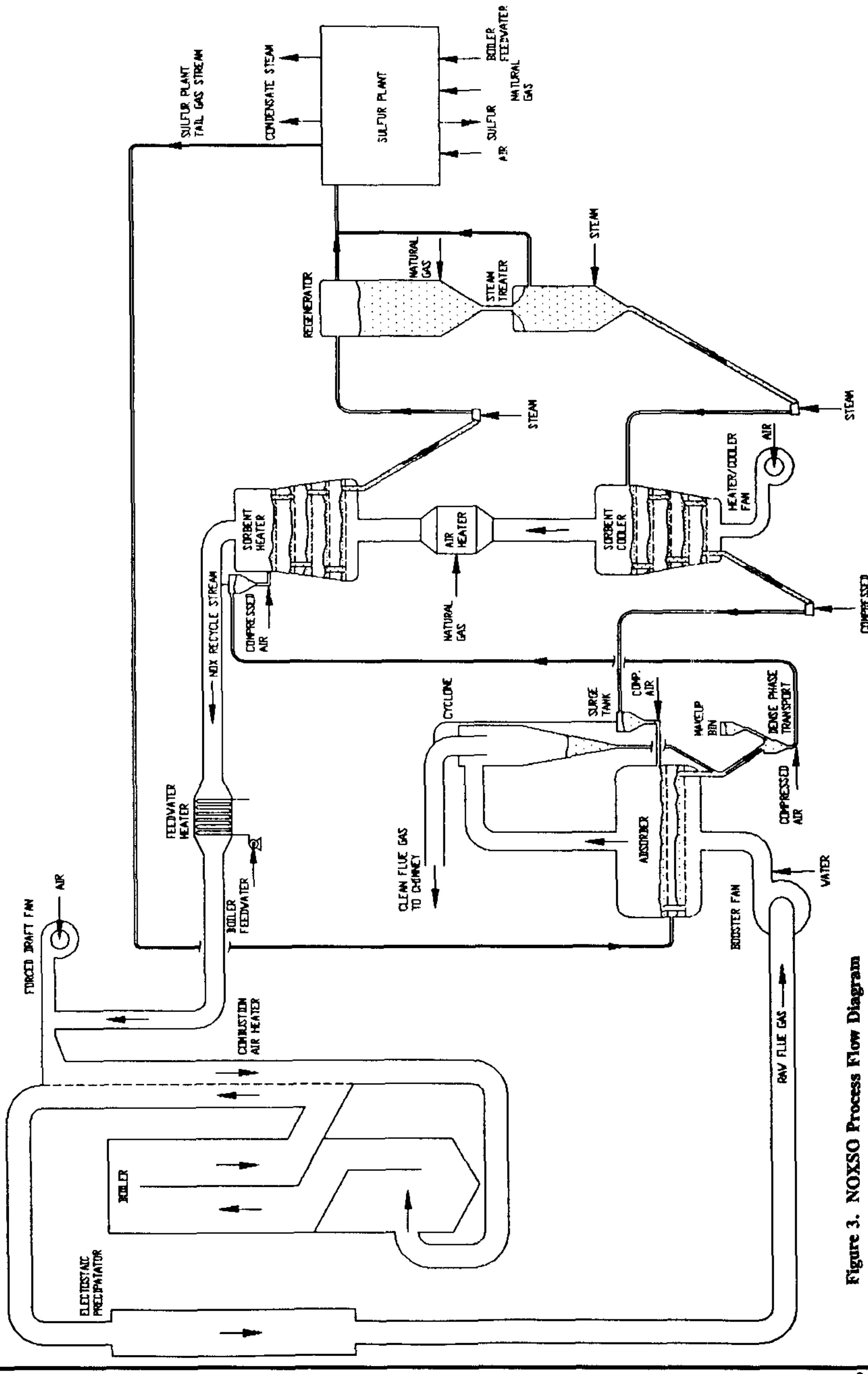


**Figure 3. NOXSO Process Flow Diagram**

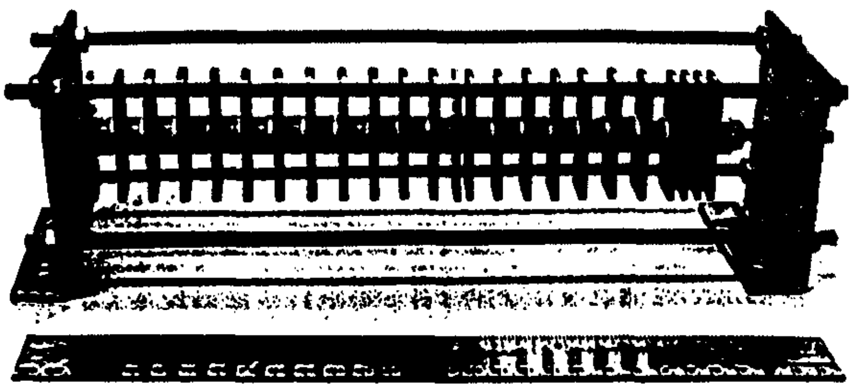

Figure 4. Photograph of Corrosion Spool

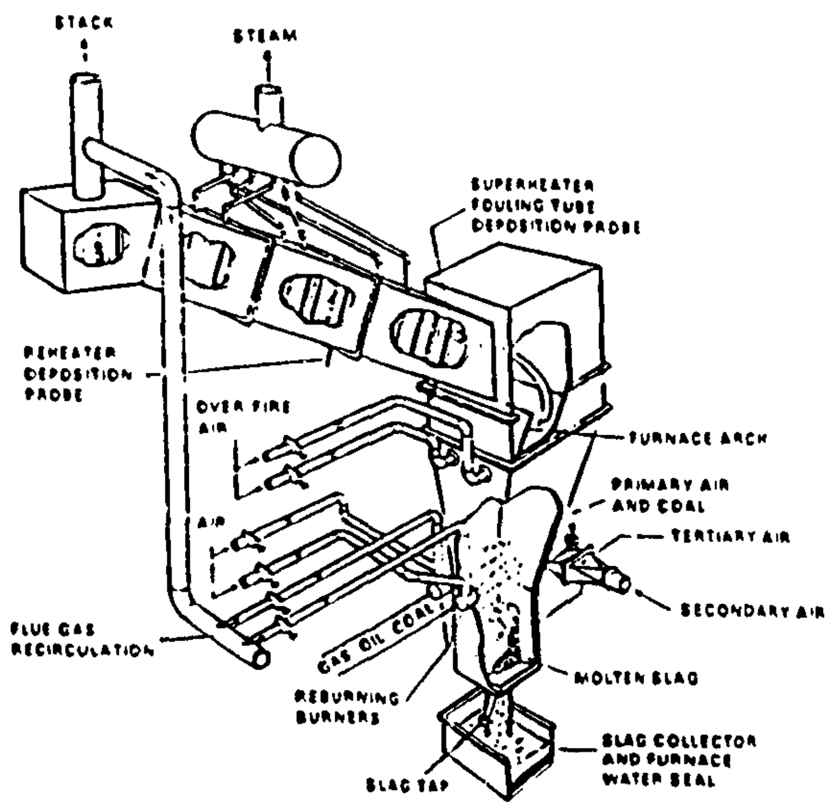


Figure 5. Babcock & Wilcox's Small Boiler Simulator (SBS) Schematic

# OVERVIEW OF THE MILLIKEN STATION CLEAN COAL DEMONSTRATION PROJECT

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## INTRODUCTION

In September, 1991, the United States Department of Energy awarded New York State Electric and Gas (NYSEG) a Clean Coal Technology Round IV grant for the Milliken Clean Coal Demonstration Project. The two unit, 320 MW Milliken Station is located in the town of Lansing, New York. The Milliken project proposed a Total Environmental and Energy Management (TEEM) concept. The project team members include NYSEG, CONSOL Inc., Saarberg-Hölter-Umwelttechnik (S-H-U), NALCO/Fuel Tech, Stebbins Engineering and Manufacturing Company, and an air heater vendor. The Milliken project goals are to:

- Reduce $SO_2$ emissions by up to 98% using a low power-consuming scrubber system while burning high-sulfur coals,
- Reduce $NO_x$ emissions through application of low $NO_x$ burners and the NOxOUT® process,

- Minimize solid waste production through the sale of gypsum, mixed chloride salts, and continued fly ash sales,
- Demonstrate zero waste-water discharge,
- Minimize the impact of the environmental control systems on station thermal efficiency, and
- Maintain superior system availability.

The project components were selected to achieve superior environmental performance at reduced cost with minimal impact on station efficiency or net plant heat rate. Currently, NYSEG and DOE are negotiating the Clean Coal Technology IV Cooperative Agreement. This paper will present the project schedule, the proposed process design, and the process component performance objectives.

## SCHEDULE

The project schedule is presented in Figure 1. Since this project is a compliance project for Phase I of the Clean Air Act Amendments of 1990, the schedule was set to meet the $SO_2$ and $NO_x$ emission requirements in 1995. The design and construction period lasts from January 1992 to March 1995. During this period, Milliken Units 1 and 2 (160 MW each) will be retrofitted with the ABB/Combustion Engineering Low $NO_x$ Concentric Firing System III (LNCFS III) and the S-H-U FGD process. One unit will be upgraded with the NOxOUT process, a high-efficiency air heater, and the CAPCIS corrosion monitoring system. The three-year demonstration period will start in March 1995.

## PROJECT DESCRIPTION

### $SO_2$ Emission Control

The Milliken project $SO_2$ control system goals are: up to 98% $SO_2$ removal while firing a 3.2% sulfur coal, low energy consumption (approximately 1% of station net output), space-saving design, and 95% FGD reliability. The S-H-U wet flue gas desulfurization process is the heart of the project. A simplified process flow diagram of the S-H-U installation for the Milliken Station is presented in Figure 2. The S-H-U process is a formic acid-enhanced wet limestone technology which produces high-quality, commercial-grade gypsum as a by-product [1].

The Milliken project features unique equipment design, construction methods, and materials of construction. The S-H-U process will handle the flue gas from two boilers in a single, split, Stebbins tile, reinforced-concrete constructed absorber module. This versatile method of construction can operate continuously in a pH range of 3 to 12. pH excursions above or below this range can be tolerated with little adverse effect. The liquid temperature limit is 200°F and the gas temperature limit is much higher. The reinforced concrete/tile construction can tolerate chloride levels in excess of 100,000 ppm. The Stebbins tile material will decrease life-cycle cost and reduce maintenance frequency due to the superior corrosion and abrasion resistance of the tile in FGD applications. Typical Stebbins FGD installations are presented in Figures 3 and 4. The reinforced concrete/tile split-module design will provide greater operational flexibility and reliability for the two Milliken units than a single absorber module. The cost of the split module is less than the cost of two separate absorber vessels of similar design and construction. The split module will be constructed below the flues. This design feature saves space, reduces retrofit costs, and can be constructed in confined spaces using Stebbins construction methods. The system will be installed without a spare absorber module to save capital costs. A computer-generated drawing of the Milliken FGD installation is presented in Figure 5.

As presented in Table 1, the S-H-U process has a significantly lower energy consumption than conventional wet limestone FGD systems because of its lower pressure drop and liquid-to-gas ratio. Because the S-H-U process is based on formic acid buffering of the recycle slurry, it is inherently stable under all process conditions and has virtually no scale potential. Since one of the Milliken project goals is zero waste water discharge, an important additional benefit of formic acid buffering is a lower FGD blowdown rate than a conventional scrubber. The smaller blowdown rate is due to the ability of the S-H-U process to maintain high $SO_2$ removal and high calcium utilization with greater than 50,000 ppm chloride in the recycle slurry.

## $NO_x$ Emission Control

$NO_x$ emission reductions will be achieved by a combination of the LNCFS III system and the NOxOUT process. NYSEG intends to retrofit the ABB/CE LNCFS III low-$NO_x$ system on each Milliken unit [2]. The burner configuration for one boiler corner is presented in Figure 6. The design goals for the low-$NO_x$ burners are $NO_x$ emissions of 0.37 lb/MM Btu while maintaining high carbon burnout, i.e., producing fly ash with low loss on ignition.

The NOxOUT system provided by NALCO/Fuel Tech is a low capital cost, energy-efficient method of reducing $NO_x$ emissions. A simplified NOxOUT process flow diagram is presented in Figure 7. The goal for the NOxOUT demonstration is to reduce $NO_x$ emissions from 0.37 lb/MM Btu to less than 0.26 lb/MM Btu. The major components of the NOxOUT process are NOxOUT A reagent storage, dilution water, atomization air, and reagent injection systems [3]. The NOxOUT process will be demonstrated on the unit equipped with the zero air leakage air heater and the CAPCIS system.

The overall objective of the $NO_x$ program is to minimize the $NO_x$ emissions in a cost-effective, energy-efficient manner while minimizing impacts on boiler equipment and marketable fly ash, gypsum, and mixed chloride salts.

## Minimize Waste Production

Another Milliken project goal is to minimize solid and liquid waste production. To achieve this, the scrubber system is designed for zero waste water discharge and to produce the maximum amount of marketable, solid by-products. NYSEG intends to continue the sale of fly ash from the Milliken Station.

The scrubber and auxiliary systems are designed to produce marketable by-product gypsum and mixed chloride salts. A simplified process flow diagram of the gypsum dewatering area is presented in Figure 8. A gypsum bleed stream from the scrubber will be fed to hydroclones. The primary hydroclone underflow will feed a vacuum belt filter. The filter cake, which contains about 10 percent free moisture, will be dried and agglomerated.

A bleed stream from the gypsum dewatering area will be pumped to the blowdown treatment area. A simplified FGD blowdown treatment process flow diagram is presented in Figure 9. The blowdown treatment system includes two principal subsystems: blowdown pretreatment and brine concentration. The blowdown pretreatment subsystem includes separate stages for gypsum desaturation and heavy metals precipitation, magnesium hydroxide precipitation, possibly salt conversion from calcium chloride to sodium chloride, and ammonia stripping. The brine concentration subsystem is separated into distillate and concentrated brine phases and a drying stage for further dewatering of the brine.

In the blowdown pretreatment subsystem, the pH of the bleed stream is increased by the addition of lime slurry to remove heavy metals from solution by precipitation as metal hydroxides. Gypsum seed crystals are recycled from the clarifier/thickener to accomplish gypsum desaturation. Additional removal of heavy metals is obtained by their precipitation as sulfides through organosulfide or sodium sulfide dosing. After coagulation and flocculation, the waste water is separated into liquid and sludge phases in a clarifier/thickener. The magnesium ions in the supernatant are precipitated as magnesium hydroxide by pH adjustment with lime or sodium hydroxide. The magnesium hydroxide sludge and heavy metals sludge are dewatered in a filter press for landfill disposal. Following magnesium hydroxide precipitation, the blowdown contains primarily calcium chloride, with some sodium chloride. Sodium carbonate can be added to convert calcium to sodium salts and the calcium carbonate by-product can be recycled to the FGD system.

Ammonia slip (less than 2 ppm) from the NOxOUT process is scrubbed by the S-H-U process. The ammonium ions are removed by steam stripping prior to lowering the brine pH.

A simplified brine concentrator process flow diagram is presented in Figure 10. In the brine concentration process, the pretreated blowdown is pH-adjusted by addition of acid, preheated, deaerated, heated to near the boiling point, and fed to the falling-film evaporator. Distillate from the evaporator is returned to the FGD system with less than 10 ppm dissolved solids. The concentrated brine can be spray dried to produce dry calcium chloride or sold as a solution. Dried solids are collected in a storage silo.

Minimal Impact on Station Efficiency

The impact of the scrubber system on Milliken Station thermal efficiency will be minimized by the installation of a zero-leakage, high-efficiency air heater; improved boiler control system including boiler advisory control software; and operating the air heater at a reduced flue gas exit temperature. Energy efficiency benefits and emission reductions will result through increased boiler efficiency, decreased power requirements for the forced and induced draft fans, and lower power requirements for the scrubber recycle pumps. NYSEG estimates that the efficiency improvements will off-set the scrubber energy demand. The TEEM approach will have minimal impact on the net plant heat rate.

A CAPCIS corrosion control system will be installed downstream of the new air heater. The CAPCIS system is an on-line, real-time corrosion monitor. The signal from the CAPCIS system will be used to adjust the flue gas exit temperature by varying the volume of air bypassed around the air heater. This system will minimize the net plant heat rate and simultaneously avoid costly maintenance due to acid corrosion.

## TEST PROGRAM

NYSEG plans to have the TEEM approach operational in 1995. NYSEG plans to evaluate the impact of coal sulfur content, concentration of formic acid in the recycle slurry, and in-service spray-header combinations on S-H-U process performance. The S-H-U process variables are presented in Table 2. The goals of the S-H-U evaluation are to demonstrate 95-98% $SO_2$ removal while maintaining 95% FGD reliability, determine the impact of the

FGD on net plant heat rate, and confirm limestone utilization and formic acid makeup requirements. Using the base coal, the project will also evaluate the impact of scrubber variables on $SO_2$ removal, by-product gypsum quality, and calcium chloride quality.

The $NO_x$ control test program is divided into two parts: the Low $NO_x$ Concentric Firing System with the boiler thermal efficiency advisor software and the NOxOUT process. As shown in Table 3, the low $NO_x$ burner test program variables include economizer $O_2$ level, secondary air split between overfire air ports and concentric air, and angle between fuel air and the concentric air. The goal of the low-$NO_x$ burner test program is to maximize the $NO_x$ reduction with acceptable waterwall slagging, tube corrosion, and carbon carryover in the fly ash.

The NOxOUT test program goals are (1) to increase $NO_x$ removal by an additional 30% above the LNCFS III removal while maintaining ammonia slip below 2 ppm in the flue gas, and (2) to evaluate the impact of the NOxOUT process on the air heater, ESP and scrubber performance; and on the bottom ash, fly ash, gypsum, and calcium chloride quality. The NOxOUT process variables include reagent/$NO_x$ mole ratio, reagent injection location, reagent concentration, and boiler load. The variables and variable ranges are presented in Table 4.

The balance of plant variables are presented in Table 5. The high-efficiency air heater study will optimize the net plant heat rate with minimal impact on plant availability. The plant particulate control efficiency will be evaluated across the ESP and across the S-H-U scrubber. The ESP is designed to maintain the scrubber inlet particulate flow rate at 120-145 lb/hr per boiler. The low particulate rate is required to produce salable gypsum.

Associated with the demonstration program, a trace element/air toxics balance will be conducted around the Milliken Station. The goal of the balance is to determine the effectiveness of the upgraded ESP and the S-H-U process in reducing trace element air emissions.

## SUMMARY

To summarize, the Milliken Station Clean Coal Demonstration Project goals are to:

- Demonstrate that the S-H-U process can reduce $SO_2$ emissions from the combustion of high-sulfur coal by as much as 98% while maintaining 95% scrubber reliability,
- Demonstrate that the combination of the ABB/CE LNCFS III system and the NOxOUT process can economically and reliably reduce $NO_x$ emissions,
- Minimize solid waste production and disposal through the sale of gypsum and mixed chloride salts,
- Minimize the impact of environmental control on net plant heat rate,
- Demonstrate zero waste water discharge, and
- Maintain superior system availability.

NYSEG plans an ambitious program for the Milliken Station Clean Coal Demonstration Project. NYSEG broke ground and construction is underway. The project team is looking forward to returning to this conference in 1996 to present the preliminary results from a successful demonstration program.

## REFERENCES


1. Petzel, H. K., "Development and Operating Experiences of the S-H-U FGD Process at the Völkling Power Station," 1991 $SO_2$ Control Symposium, Washington, D.C., (December 1991).
2. Hardman, R. R., Smith, L. L., and Elia, G. G., "Advanced Tangentially-Fired Combustion Technologies for the Reduction of Nitrogen Oxides ($NO_x$) from Coal-fired Boilers," International Congress on Technology and Technology Exchange, Paris, France, (May 1992).
3. Comparata, J. R., Buchs, R. A., Arnold, D. S., and Bailey, L. K., "$NO_x$ Reduction at the Argus Plant Using the NOxOUT Process," 1991 Joint Symposium on Stationary Combustion $NO_x$ Control, Washington, D.C., (January 1991).

| | S-H-U Process | Conventional Wet Scrubbing Process |
|---|---|---|
| Liquid/Gas Ratio (L/G) | 130 gal/1000 acf | 140 gal/1000 acf |
| % $SO_2$ Removal | 98 | 95 |
| Limestone Utilization | 1.01-1.02 Stoichiometry | Minimum 1.04 Stoichiometry<br>Normal >1.05 Stoichiometry |
| Auxiliary Power | 10 to 12% less | base |
| Operational Stability | Inherently stable under all process conditions | Inherently unstable during load change or varying $SO_2$ concentrations |
| Gypsum Quality | 100% of product is commercial quality gypsum | Very often requires classification (disposal stream) before usage |
| Scale Potential | Virtually none | Significant during load changes and at other times of high pH |
| Wastewater Produced | 50% less | base |

**Table 1. Comparison of FGD Design Points S-H-U vs. Conventional Wet Scrubber.**

| Variable | Variable Range | Goal |
|---|---|---|
| Coal sulfur content | 1.5, 2.9, 4.0 wt % sulfur | Up to 98% $SO_2$ removal, 95% reliability, minimize FGD energy requirement. |
| Formic acid concentration | 0, 800, 1200, 2000 ppm | Evaluate Impact of FGD on net plant heat rate. |
| In-service spray header combinations | Various spray header combinations | Confirm calcium and formic acid make-up rate. |

**Table 2. Milliken CCT-4 -- S-H-U Process Variables.**

| Variable | Variable Range | Goal |
|---|---|---|
| Economizer $O_2$ level | 2.0 to 5.0% | Maximize $NO_x$ reduction with acceptabe water-wall slagging, tube corrosion, and carbon carryover in fly ash |
| Secondary air split between OFA ports and concentric air | 0 to 30% OFA | |
| Angle between concentric air and coal stream | -15 to +15° yaw<br>-30 to +30° verticle tilt | |

**Table 3. Milliken CCT-4 -- Low $NO_x$ Concentric Firing System Process Variables.**

| Variable | Variable Range | Goal |
|---|---|---|
| Urea/$NO_x$ molar ratio | 0.15 to 1.5 | Up to 30% additional $NO_x$ removal |
| Urea injection location | up to 3 locations | Evaluate impact on air heater, ESP, FGD, and by-product quality |
| Urea concentration | 5 to 15 wt % solution | No urea or ammonia contamination of by-products |
| Boiler load | 75 to 100% capacity | |

**Table 4. Milliken CCT-4 NOxOUT Process Variables.**

| Area | Variable | Variable Range | Goal |
|---|---|---|---|
| Air Heater | Air heater gas exit temperature | 240 to 300°F | Optimize net plant heat rate with minimal adverse effect on plant operations |
| | Economizer $O_2$ level | 2.0 to 5% $O_2$ | Determine impact on boiler efficiency and fly ash LOI |
| Particulate Control | Coal sulfur content | 1.5, 2.9, 4.0 wt % sulfur | 0.1 lb/MM Btu particulates at scrubber inlet |
| | ESP power | | 0.05 lb/MM Btu particulates at scrubber outlet |

**Table 5. Milliken CCT-4 -- Balance of Plant Variables.**

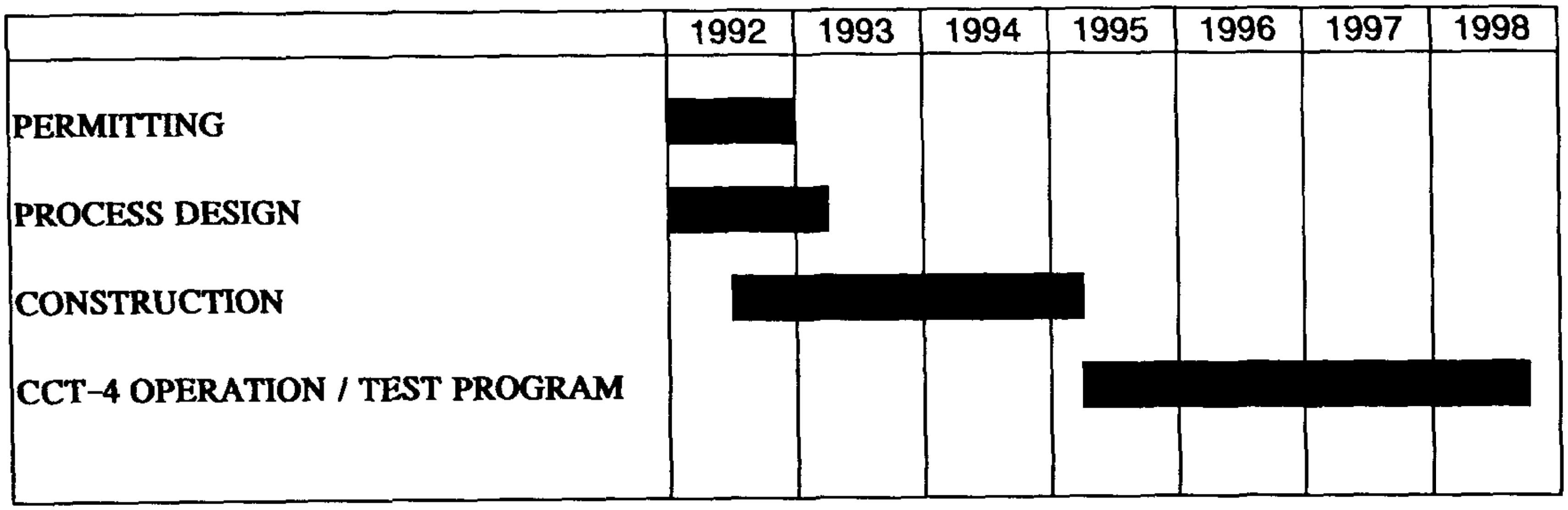


**Figure 1.** **New York State Electric & Gas Corporation Milliken Station Clean Coal Project Milestone Schedule.**

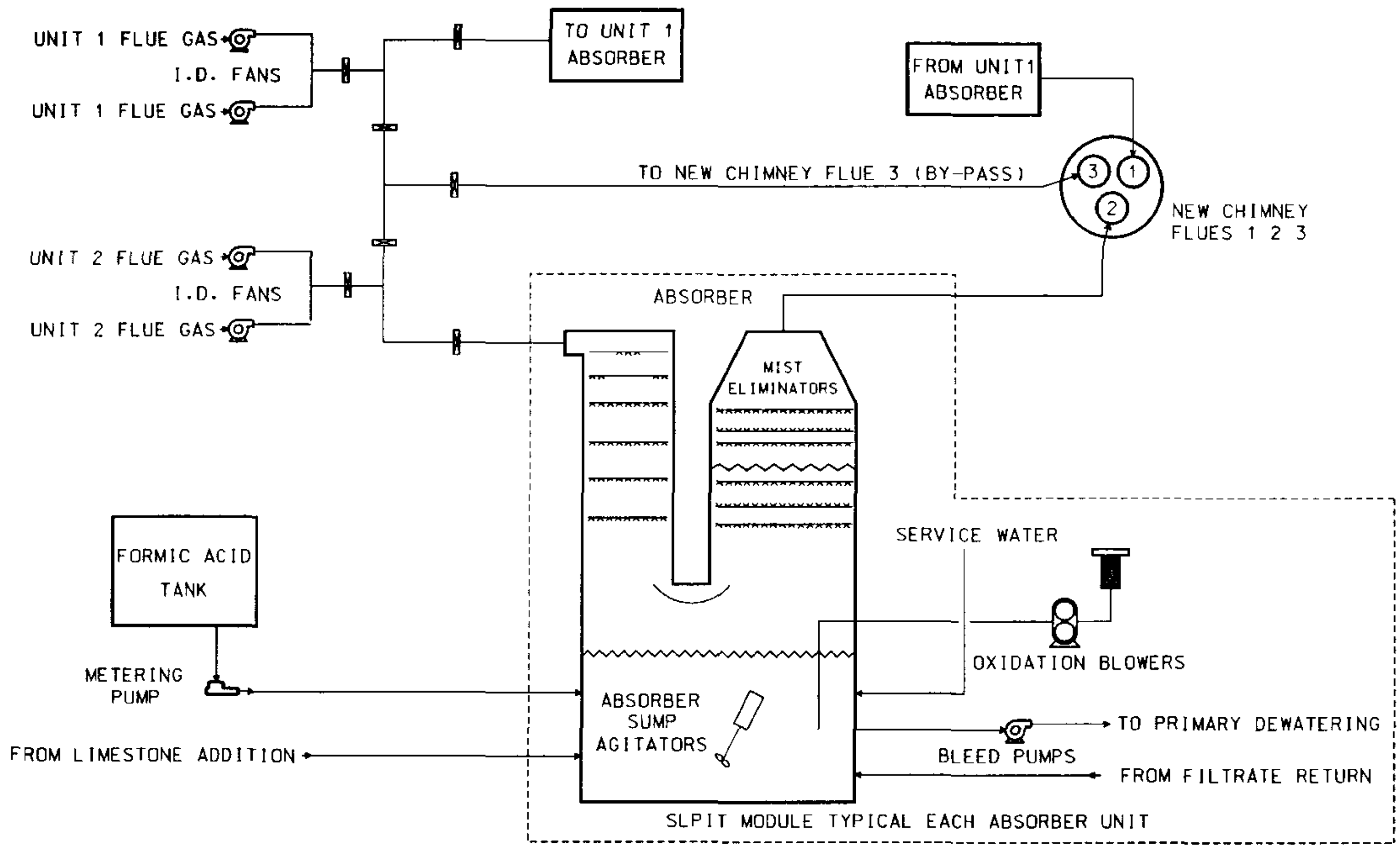


**Figure 2. Simplified S-II-U Process Flow Diagram.**

**Figure 3.** Reinforced Concrete/Tile Wall and Baffle Under Construction.

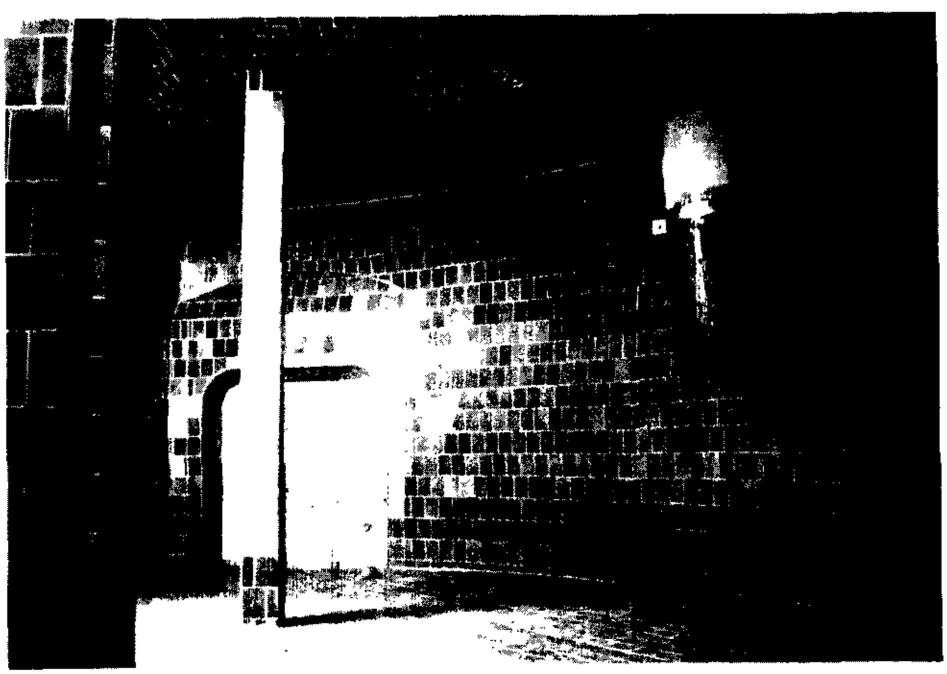

**Figure 4.** Completed Reinforced Concrete/Tile Constructed Tank.

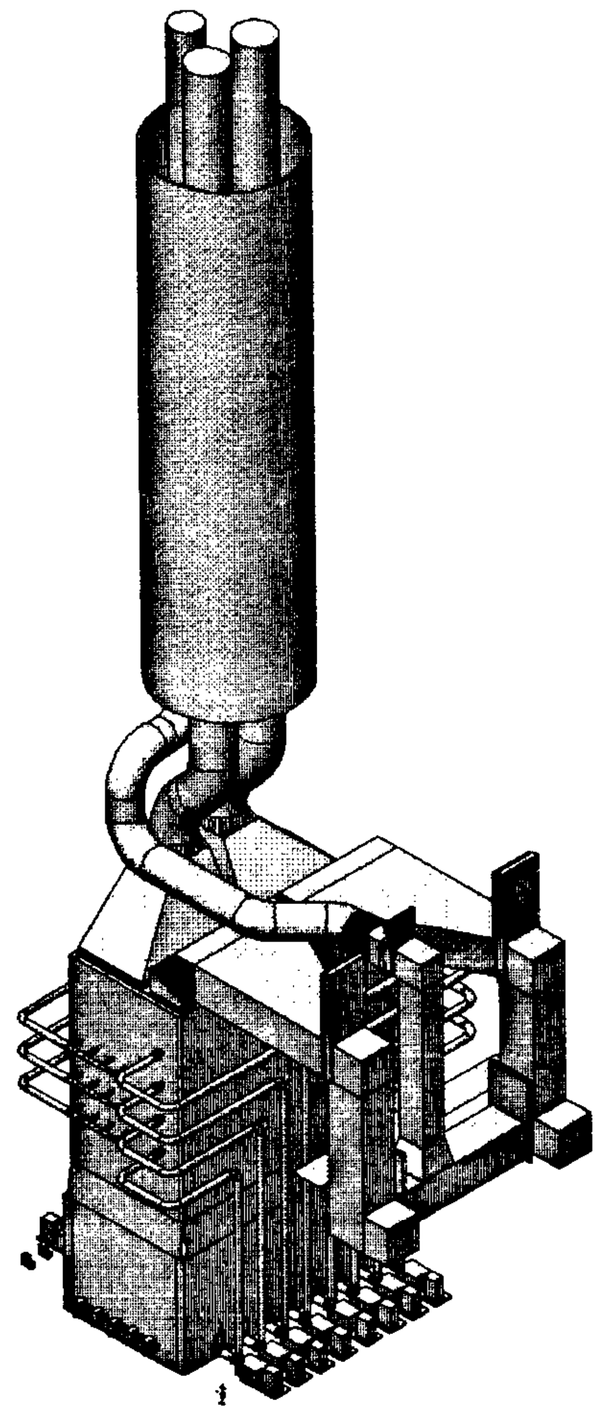

**Figure 5. Computer-Generated Drawing of the Milliken FGD Installation.**

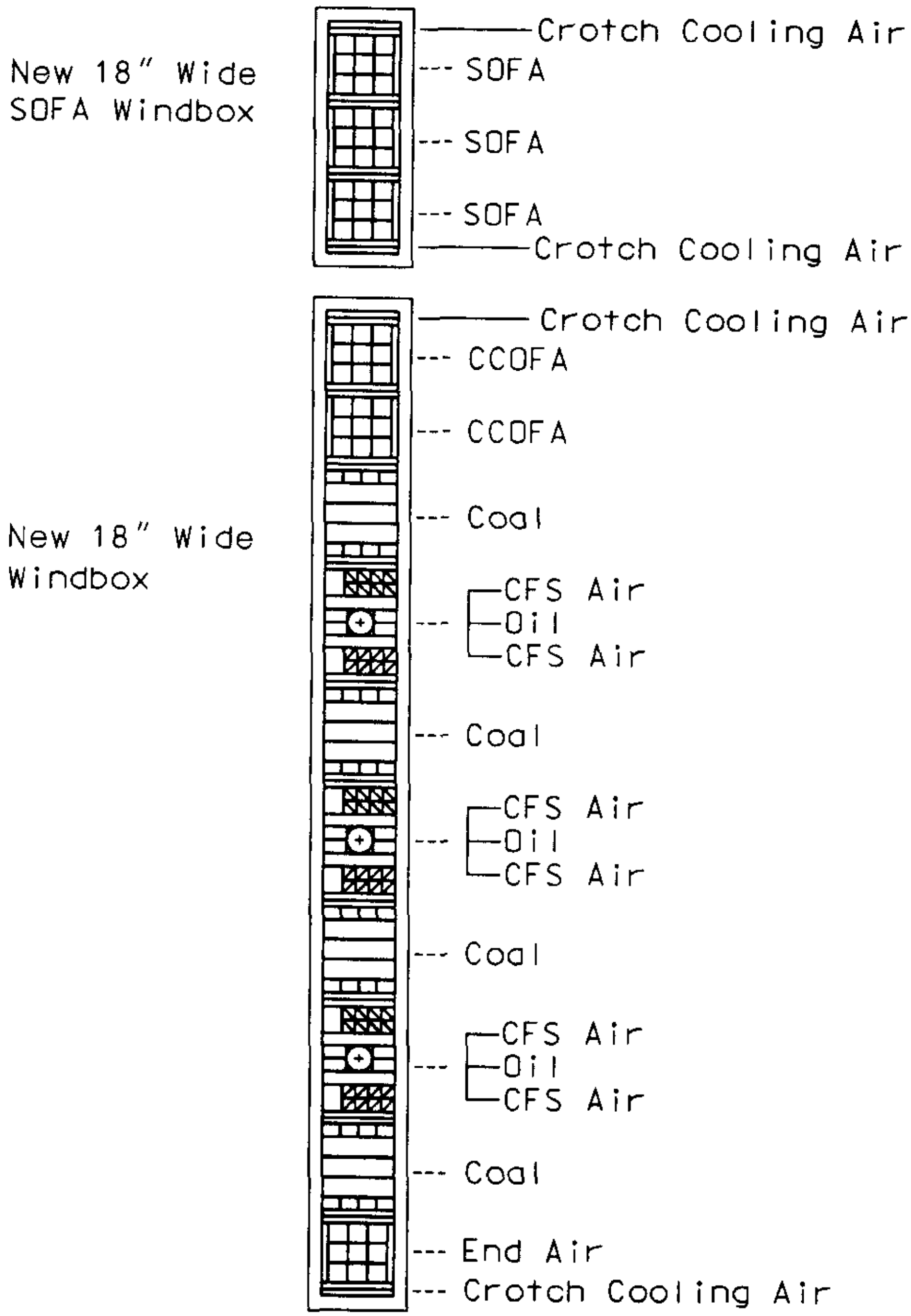


**Figure 6.** **ABB/CE Low $NO_x$ Concentric Firing System Level III.**

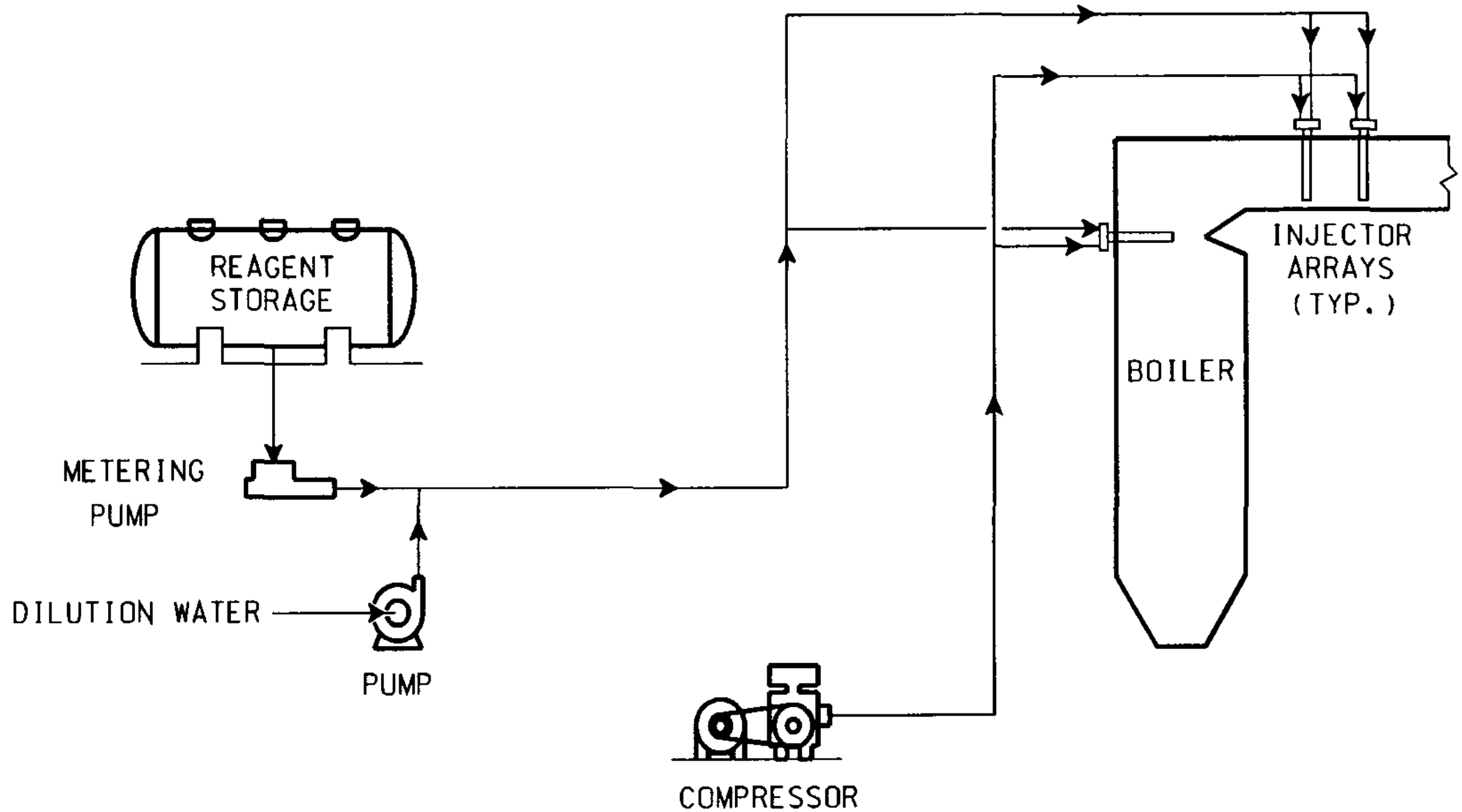


**Figure 7.** **Simplified NOxOUT® Process Flow Diagram.**

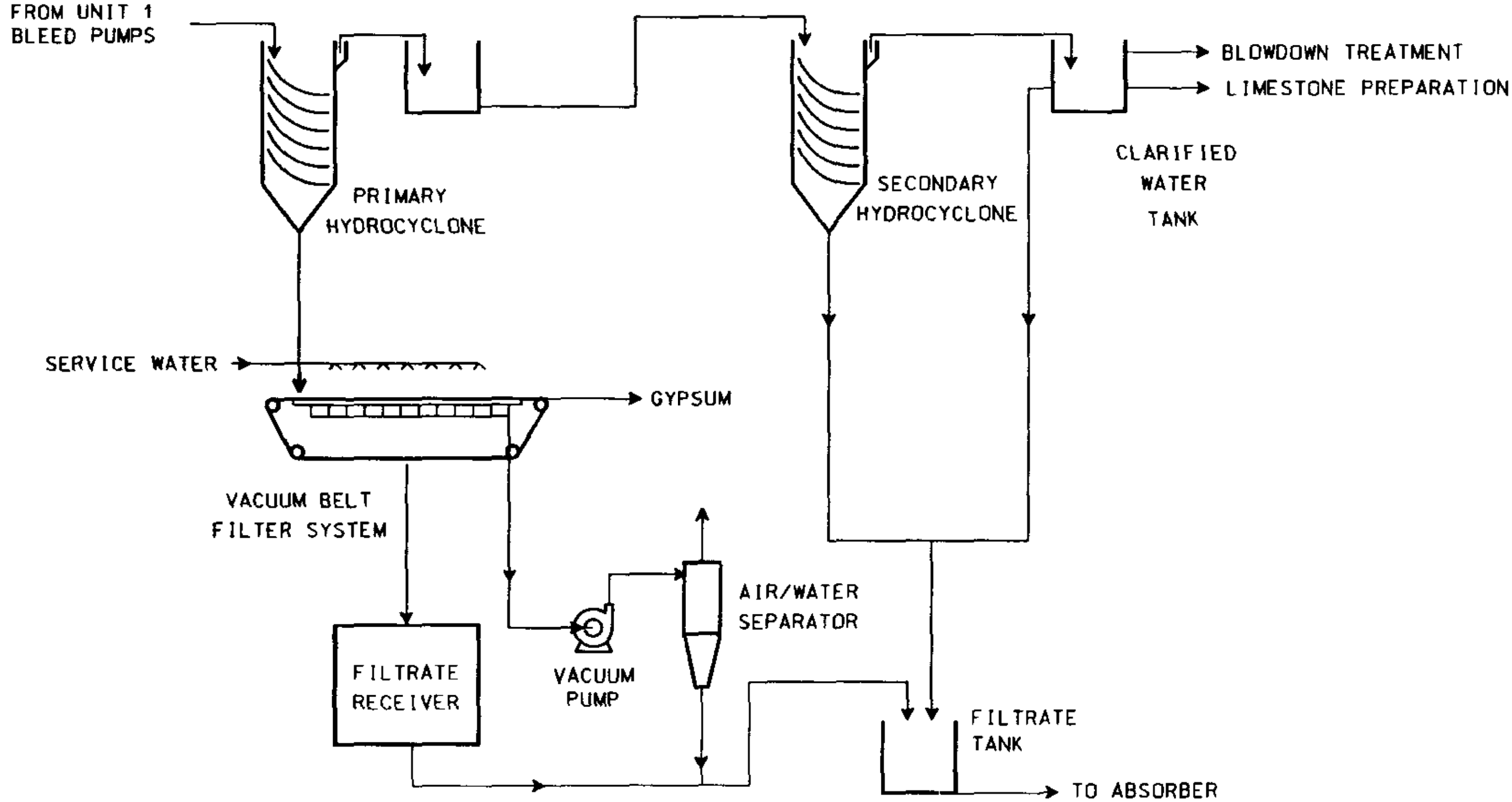


**Figure 8.** **Simplified Gypsum Dewatering Area Process Flow Diagram.**

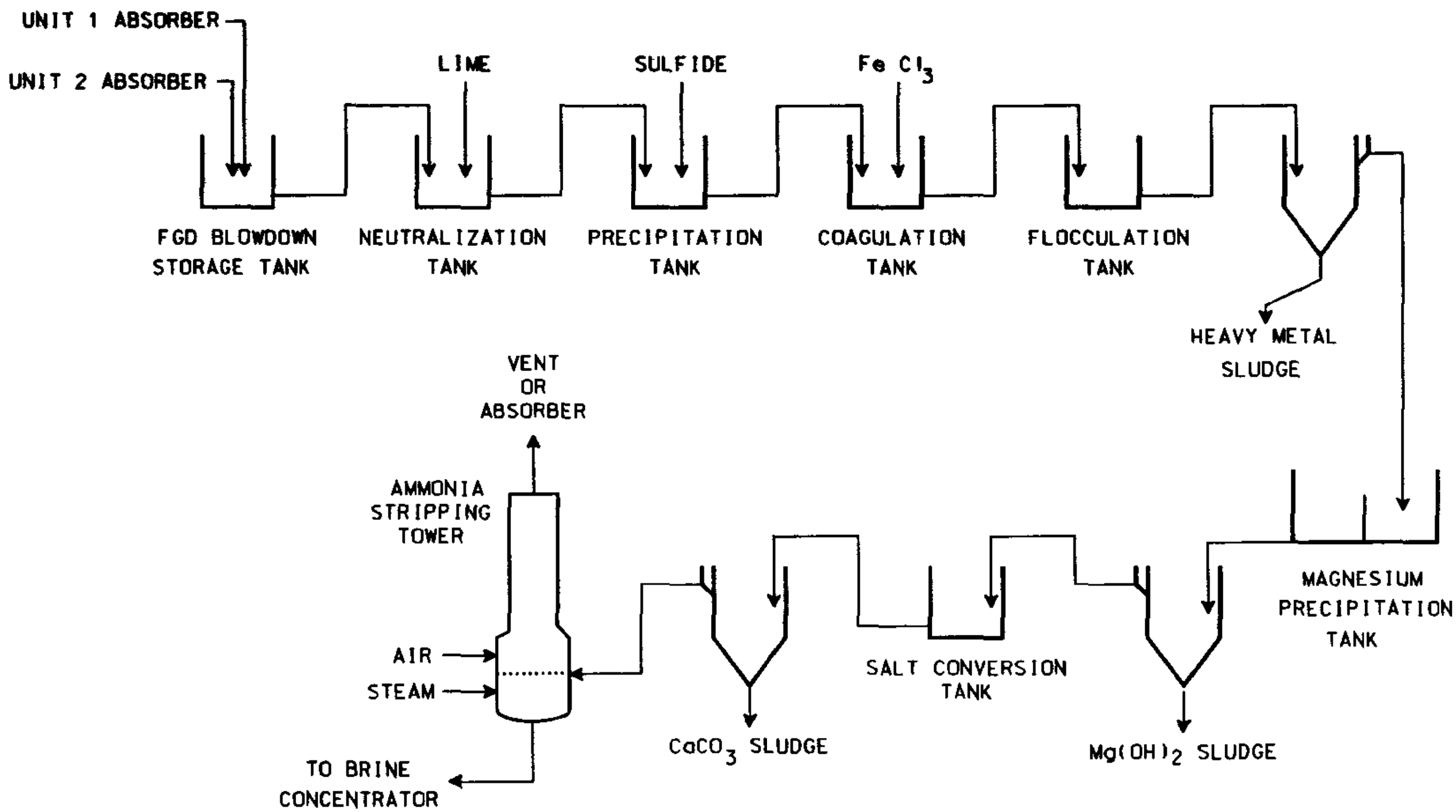


**Figure 9.** Simplified FGD Blowdown Treatment Process Flow Diagram.

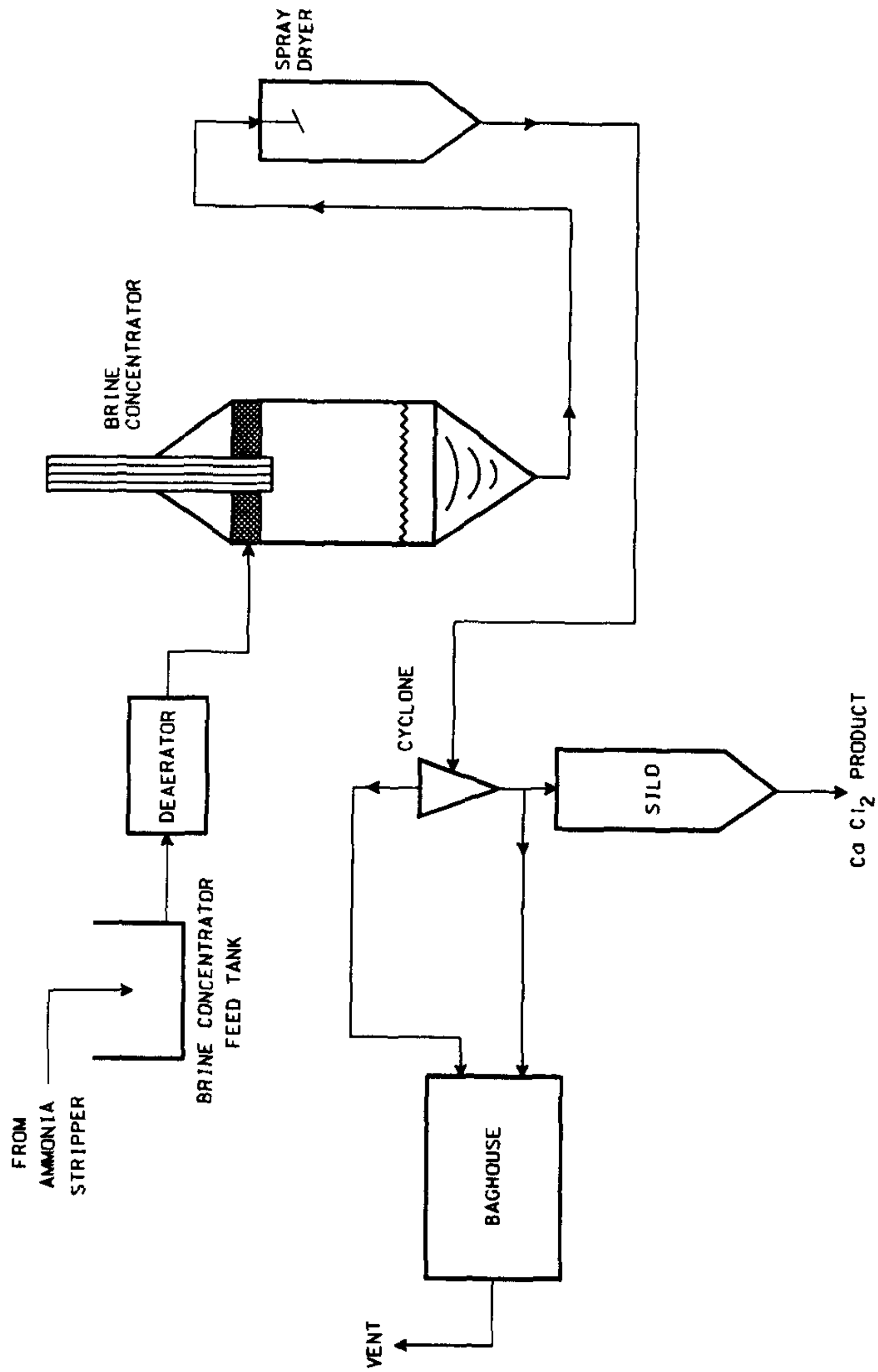


**Figure 10. Simplified Brine Concentrator Process Flow Diagram.**

# SESSION 3:
# Advanced Power Generation Systems

*Chair: R. Daniel Brdar, DOE METC*

**York County Energy Partners DOE CCI ACFB Demonstration Project,**
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**Coal Gasification — An Environmentally Acceptable Coal-Burning Technology for Electric Power Generation**, Lawrence J. Peletz, Jr., Consulting Engineer, ABB Combustion Engineering, Inc. Co-authors: Herbert E. Andrus, Jr., and Paul R. Thibeault, ABB Combustion Engineering, Inc.

**Toms Creek IGCC Demonstration Project**, Gordon A. Chirdon, Director of Engineering and Technology, Coastal Power Production Company.
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# YORK COUNTY ENERGY PARTNERS DOE CCI ACFB DEMONSTRATION PROJECT

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## ABSTRACT

The York County Energy Partners (YCEP) project, to be located in York County, Pennsylvania, will demonstrate the world's largest atmospheric circulating fluidized bed boiler under sponsorship of the U.S. Department of Energy's Clean Coal Technology I Program. The single ACFB boiler, designed by Foster Wheeler Energy Corporation, will produce 227 MWe of net electrical power and export approximately 50,000 lb/hr of steam. This paper explains how the technical challenges to the design of a utility-scale ACFB boiler were met and presents the innovative features of this design.

## INTRODUCTION

The York County Energy Partners cogeneration project located in York County, PA will demonstrate the world's largest atmospheric circulating fluidized bed (ACFB) boiler under sponsorship of the US Department of Energy's (DOE) Clean Coal Technology I Program. The goal of the project is to demonstrate the technical and economic feasibility of applying circulating fluidized bed combustion technology at the 250 MWe scale for producing electrical power and steam in an environmentally acceptable manner while efficiently utilizing our nations coal resources. An artists rendition of the completed YCEP Cogen plant is presented in Figure

1. The single-train ACFB boiler, designed by Foster Wheeler Energy Corporation (FWEC), will supply 227 MWe of electrical power to the Metropolitan Edison Company (Met-Ed) and export approximately 50,000 lb/hr of steam to the J. E. Baker Company. The steam supplied by the YCEP project will reduce existing propane, natural gas, coal, and electricity consumption at the J. E. Baker Company, a producer of dead-burned dolomite which is used to manufacture refractory bricks for the steel and cement industry, specialty granular refractories for repairing and maintaining furnace linings, and agricultural products.

The YCEP Cogen Project will be located approximately 6 miles west of the City of York, PA in West Manchester Township. The project is situated adjacent to the J. E. Baker Company's dolomite operations, which is north of U.S. Route 30. As shown on the map in Figure 2, the 50 acre triangular site is bounded to the northeast by Emigs Mill Road (SR 4003), to the south by the Yorkrail railroad line, and to the northwest by the Briarwood Golf Club. The project will interconnect to Met-Ed's Jackson substation, which is located within 7000 feet of the project site and is capable of distributing the electrical power that will be produced.

A plot plan for the YCEP Cogen project is shown in Figure 3. Fuel delivery will be facilitated by direct access to the Yorkrail Company rail line. A loop track will be constructed to allow the coal to be unloaded on site. Sufficient space is allotted for 30 day storage of coal at the site.

A summary of the YCEP Cogen project information is given in Table 1. The ACFB combustor will be fueled with low sulfur (less than 2 percent) bituminous coal available locally in Western PA, MD, and W. VA. The scaled-up single ACFB boiler will generate 1,725,000 lb/hr of main steam at 2500 psig and 1005°F and 1,400,000 lb/hr of reheat steam at 442 psig and 1005°F. The estimated total cost of the YCEP Cogen project is more than $ 300 million dollars. A cost share of approximately $ 75 million dollars will be provided by the US DOE to sponsor the Clean Coal Technology Round I Demonstration Test Program.

A schedule of the milestones of the YCEP Cogen project is provided in Table 2 and as a Gantt chart in Figure 4. Adjustments to this schedule may be necessary to accommodate certain Department of Energy requirements which are not yet available to the project sponsor. Commercial operation is scheduled to begin by March, 1997.

## Facility Description

A brief description of the overall cogeneration process is given below. For reference, Figure 3 provides a plot plan for the entire plant and Figure 5 provides a process flow diagram indicating how the major pieces of equipment are interconnected.

Fuel is fed to the base of the combustor along both the front and back walls and sorbent is fed to the base of the combustor along the front wall. A fuel and sorbent receiving and preparation system is incorporated into the plant design. Primary and secondary air flows to the combustor are provided by primary and secondary air fans. Before entering the combustor, these streams are preheated via heat exchange with the flue gases in the air heaters. The heart of the process is a circulating fluidized bed combustor in which the fuel is combusted while simultaneously capturing $SO_2$. Selective non-catalytic reduction of NOx emissions is accomplished through injection of aqueous ammonia at the inlet to the cyclones. Solid particles entrained by the upflowing gas in the combustor exit the top of the combustor into cyclones which efficiently separate the flue gas from the entrained particles. The flue gas discharged from the cyclone is directed to the downstream convective section of the boiler and the captured solids are recycled to the base of the ACFB by means of standpipes, J-valves, and an INTREX$^{TM}$ fluidized bed Integrated Recycle Heat Exchanger. The J-valves provide a seal between the positive pressure in the lower furnace where the recycle solids are fed and the near ambient pressure in the cyclones.

Coarse ash material (bed ash) accumulating in the ACFB is removed from the bed using a specially designed directional grid and a fluidized bed stripper cooler. The bed ash is cooled by the fluidizing air flow to the stripper cooler. This heated air stream flows to the combustor along with the fines that are stripped out. The cooled bed ash will be conveyed to a bed ash silo. Fly ash collected in the air heaters, economizer, and baghouse hoppers will be pneumatically conveyed to the fly ash storage silo. Depending on the beneficial use for the byproduct ash, the bed and fly ash streams may require additional processing to condition the ash.

A schematic diagram of the steam/water circuitry for the ACFB steam generation system is shown in Figure 6. Boiler feedwater is preheated in the economizer located in the convection heat recovery area. The preheated feedwater is then routed to the steam drum. From the steam drum, the pressurized water flows by natural circulation through the waterwall sections of the ACFB combustor and the INTREX$^{TM}$ heat exchanger. Steam generated in the waterwall boiling circuits is routed to the cyclone enclosure walls, the convection heat recovery area enclosure walls, the primary superheater, and then on to the intermediate and finishing steam coils located in the INTREX™ heat exchanger. This superheated steam flow is expanded through a high pressure steam turbine. A portion of the steam exiting the high pressure turbine flows through a reheater located in the convective heat recovery area. The reheated steam is expanded through an intermediate pressure steam turbine to extract additional power.

A description of the major components which comprise the coal-fired ACFB cogeneration plant is given below.

Circulating Fluidized Bed Combustor

A process flow diagram for the YCEP cogeneration plant is shown in Figure 5. Figure 7 provides a side elevation drawing of the ACFB combustor/steam generation system. Coal and sorbent, such as limestone, are fed into the lower, refractory-lined portion of the atmospheric circulating fluidized bed where these feedstock materials are mixed with the bed material and initial combustion occurs. To support combustion of the coal, a substoichiometric amount of air is fed to the base of the unit and additional air is injected at two different elevations above the primary air feed location. The total air flow is approximately 20% in excess of stoichiometric requirements. Primary air enters through a specially designed air distribution grid. This process of staging the air flow to the combustor minimizes the formation of NOx within the unit. In addition, the relatively low operating temperature of the ACFB combustor of 1550-1650°F also minimizes NOx formation. The sorbent is fed to the bed to capture $SO_2$ formed by the combustion of sulfur-containing fuel. Calcium carbonate is calcined to calcium oxide *in-situ* which subsequently reacts with $SO_2$ and $O_2$ to stabilize the sulfur in the form of calcium sulfate. Maintaining the bed temperature at approximately 1600°F is also necessary for effective sulfur capture and to minimize sorbent consumption.

The upflowing combustion gases entrain the fine ash, char, and sorbent particles producing a net flow of solids up through the combustor. The combustor temperature is maintained by efficient transfer of heat from the gas-solid suspension to the waterwall tubes. Solids entrained from the bed, including unburned char and unreacted sorbent particles, are captured by hot cyclones and returned to the ACFB combustor. This promotes improved combustion and sorbent utilization efficiency. The recycled solids are also cooled upon passing through the steam-cooled cyclones and the INTREX™ heat exchanger. A side elevation drawing of the INTREX™ unit is given in Figure 8. The cooled recycle solids stream also helps to moderate the temperatures within the combustor. Coarse ash particles are removed from the bottom of the combustor as bed ash. Additional heat is recovered from flue gas and fine ash particles escaping the cyclones within the convective section of the boiler. The fly ash is captured in a baghouse before the cooled flue gas is exhausted through a stack.

## Description of the Integration of Components

### Fuel and Sorbent Preparation and Feed System

Bituminous coal is delivered to the site by rail and is stored in five 56 ft diameter coal storage silos with a 14 day storage capacity. The 2" x 0 size raw coal is then conveyed to crushers located at the top of the boiler building to be crushed to 1/2" x 0 size and stored in 4 in-plant coal silos. The crushed coal is extracted from the silos at variable rates, as required by the ACFB boiler, by gravimetric feeders and fed to both front and rear walls of the boiler.

Depending on the source of the raw limestone and dolomite, the sorbent would be either delivered by pneumatic truck or crushed at an adjacent site and pneumatically conveyed to two sorbent storage silos. Each silo discharges to one (1) 100% capacity gravimetric belt feeder. From the feeders, the sorbent is dropped into a bifurcated discharge hopper where the sorbent is divided into two streams. Four (4) 50% capacity sorbent blowers convey the sorbent to the ACFB boiler pneumatically and inject it to the boiler at the vicinity of coal feed points. The rate of sorbent feed is automatically adjusted if the $SO_2$ concentration measured at the stack exceeds a predetermined set point.

### Draft System

The ACFB boiler is equipped with one (1) 100% capacity centrifugal primary air fan, one (1) 100% capacity centrifugal secondary air fan, two (2) 100% capacity centrifugal INTREX™ heat exchanger blowers, two (2) 100% capacity positive displacement J-valve blowers, four (4) 50% capacity positive displacement sorbent blowers. The primary air and the secondary air are heated by the flue gas in two heaters arranged in parallel with multiple air and flue gas passes. With flue gas flowing on the inside of the vertical tubes, the gas side cleanliness is maintained without steam sootblowing. Balanced furnace draft is maintained by one (1) 100% capacity centrifugal induced draft fan. Part of the primary air bypasses the primary air heater and is used to fluidize the stripper/coolers and provide seal and sweep air for the fuel feeders. Part of the high pressure air from the J-valve blowers is injected into the transfer lines from the combustor to the stripper/coolers to assist solids movement into the stripper/cooler.

## Baghouse

A 14-compartment reverse air type baghouse filter system will be used to clean the flue gas exiting the primary and secondary air heaters. The baghouse filter system is designed to remove particulates in the flue gas and maintain particulate emissions below 0.015 lbs/MMBtu. A design air-to-cloth ratio of two is specified with one compartment isolated for cleaning and one compartment out for maintenance. Each baghouse compartment has a hopper which is heat traced and has an 8-hour storage capacity. The ash collected in the hopper will be discharged to the fly ash removal system.

## Spent Bed Material Cooling System

Coarse coal ash, spent sorbent, and calcium sulfate must be removed from the bottom of the ACFB boiler to control solids inventory in the lower region of the boiler. Directional air distributor nozzles are used on the furnace floor to direct coarse material to the drain openings on each furnace sidewall. Figure 9 illustrates the solid flow patterns along the base of the combustor which causes the bed ash material to drain to the stripper cooler and also maximizes the residence time of the large fuel particles in the combustor to reduce unburned carbon levels in the bed ash. Four (4) 50% capacity fluidized bed stripper/coolers are designed to selectively remove oversized bed material and return fine material back into the furnaces to increase the solids residence time. As illustrated in Figure 10, the stripper/cooler is a refractory lined box with three fluidized compartments; one stripper zone and two cooling zones. A fraction of combustion air is used to strip and cool the spend bed material to an acceptable temperature level for disposal. Sensible heat in the spent bed material is recovered by injecting the stripping and cooling air back to the furnace as part of the secondary air for combustion.

## Ash Disposal System

The cooled bed ash will be conveyed to a bed ash storage silo via a pneumatic transport system. The bed ash collected during the pilot plant tests will be used to test different ash transport systems to determine the most reliable and cost effective transport system for the bed ash. The fly ash is conveyed from air heaters, economizer, and baghouse hoppers by dilute-phase pneumatic transport system to a fly ash storage silo.

## Water Steam Circuitry

Figure 8 illustrates the components of the steam generation system that are incorporated in the ACFB design. The circulating fluid bed design is comprised of four distinct sections: the furnace, the hot cyclones, the INTREX™ heat exchanger, and the heat recovery area (HRA). All four sections are top supported and are comprised of water or steam cooled enclosures. Use of integrally welded steam generating walls (MONOWALL®) as the enclosure is in accordance with modern design practice and provides both the required cooling and the structural support. The steam circuitry is designed for natural circulation and includes a single drum located above the furnace and between the furnace and cyclones. The boiler is designed to turn down to 40 percent of MCR capacity without firing auxiliary fuel and to have a steam temperature control range between 75% and 100% MCR load.

Boiler feedwater enters the unit at the inlet to the bare tube economizer located in the convection heat recovery area. Water flows through the banks of horizontal coils countercurrent to the flue gas, exiting at the outlet header. Feedwater is then routed to the steam drum. Steam generated in the boiling circuits is separated by the steam drum internals. The steam drum internals are designed to efficiently separate the steam/water mixture, and to insure that the steam leaving the drum is moisture free and of high purity. In addition, the drum internals distribute the flow of incoming water and steam throughout the drum to maintain even drum metal temperatures. The internals consist of horizontal centrifugal separators located along the side of the drum and unit Chevron drier assemblies arranged along the top of the drum.

Steam leaving the drum through the Chevron dryers is routed to the cyclone circular enclosure walls, HRA enclosure walls, the HRA primary superheater, and then on to the intermediate and finishing superheater coils located in the INTREX™ heat exchanger. Two spray type attemperators are provided, located between the primary and the intermediate superheaters and between the intermediate and finishing superheaters to provide control of the final steam temperature. This type of attemperation will afford excellent control flexibility and will not adversely affect steam purity.

Reheat steam enters the unit at the reheater inlet header located in the parallel pass HRA. Steam flows through the reheater banks of horizontal coils countercurrent to the flue gas flow, exiting at the outlet header. Reheat temperature control is achieved through simple flue gas flow proportioning thereby eliminating the need for spray-type attemperators.

Power Generation System

The YCEP Cogeneration plant will generate electric power by extracting shaft work from the high pressure superheated steam flow produced by the ACFB steam generating circuits. The turbine generator system includes high, intermediate and low pressure steam turbines connected to a generator. Main steam enters the high pressure turbine at 1,750,000 lb/hr, 1005°F, and 2500 psig. A portion (1,400,000 lb/hr) of the main steam flow leaving the expander at 590 °F and approximately 480 psig is reheated to 1005°F and is then fully expanded. Approximately 50,000 lb/hr of extraction steam is withdrawn from the intermediate pressure turbine at 200 psig and low pressure turbine at 50 psig.

Thermal DeNOx System

Low level emissions of NOx generated by the oxidation of fuel nitrogen within the ACFB combustor will be further reduced by decomposing NOx into $N_2$, $O_2$, and $H_2O$ using non-catalytic reduction with ammonia. Aqueous ammonia will be injected directly into the flue gas in the (4) ducts connecting the cyclones to the combustor. At this location, the temperature of the flue gas at 100% MCR will be approximately 1630°F. At this temperature the NOx reduction reactions proceed at a sufficient rate to achieve a NOx reduction level of 50%. Since staged combustion and low combustion temperatures already contribute to significantly lower NOx emissions than achieved with conventional pulverized coal boilers, extremely low NOx emissions will be achieved by combining the two technologies.

Hot Model Burn Test

ACFB combustors are known for their excellent fuel flexibility. However, many fuel and sorbent characteristics, such as composition, reactivity, and friability will all impact the design and the performance of a ACFB combustor as well as the feed and the ash handling equipment. These factors must be thoughtfully addressed during the design stage to ensure the ACFB combustor and ancillary equipment will meet the performance guarantees.

Before the final design engineering for the YCEP Cogen plant begins, four (4) hot model tests will be conducted at Foster Wheeler Development Corporation's 1 MWth test facility at Livingston, New Jersey, using potential coals and sorbents considered for commercial operation. The ACFB hot model is constructed of MONOWALL® and consists of a 1'x2'x48' combustion chamber, MONOWALL®-enclosed cyclone separator and downflow heat recovery section. It is equipped with extensive temperature and pressure measurement instrumentation and gas composition analyzers to assess the combustion and emission characteristics of the FWEC ACFB combustor.

The key design information to be obtained from the hot model includes combustion efficiency, optimal temperature for sulfur capture, Ca/S molar ratio for 92% sulfur removal, emissions, and test required by environmental permit applications as well as in ash conveying and conditioning tests for the selection of proper ash handling equipment.

**Technical Challenges in Scale Up of ACFB Design**

Evolution of ACFB Technology in U.S.

The size of the YCEP ACFB combustor represents a significant increase in scale over existing ACFB combustors. Figure 11 provides an illustration of how the size of single ACFB combustors constructed in the U.S. has grown over the past decade. This bar chart of net electrical generating capacity per ACFB boiler versus the year of start-up includes primarily the larger capacity units coming on stream in this period. Currently, the largest single ACFB boiler is the 150 MWe Texas-New Mexico ACFB designed by Combustion Engineering. This unit will be superseded in 1993 by the Pt. Aconi ACFB, a 165 MWe net Pyropower combustor. However, when the YCEP project is started up in late 1996, it will become the largest ACFB combustor, capable of generating 227 MWe of net electrical power and 50,000 lb/hr of export steam. This scale will be most representative for potential utility-scale ACFB applications.

A significant challenge in the design of the single combustor ACFB for the YCEP project was to anticipate the influence that the scale of the combustor would have on its design and performance. The following sections will discuss several important considerations in designing a 227 MWe ACFB combustor having maximum certainty of successful operation. The major design features to be discussed include:

- Flexibility of Thermal Design
- Solids Mixing/Feed Distribution
- Cyclone Separator Design/Configuration

Design of ACFB Waterwall Surface

In scaling up the design of ACFB combustors, proper thermal design is important to control the temperature within the combustor. A properly designed ACFB combustor will operate at uniform 1600-1650°F temperatures, which will permit combustion to take place below the ash fusion temperature while providing optimal $SO_2$ capture with calcium-based sorbents and reduced $NO_x$ formation. This is achieved by balancing the heat released by the combustion process with the heat absorbed within the boiler. Heat absorption is achieved by withdrawing heat from the gas-solid suspension within the boiler, the cyclones, and INTREX™. Adequate heat from the gas-solid suspension within the boiler, the cyclones, and INTREX$^{TM}$ heat exchanger. Adequate temperature control and solids distribution/mixing are essential to attaining high combustion efficiencies and minimal gaseous emission rates.

Since the fluidizing velocity of ACFB's is held constant, the cross-sectional area of the combustor increases proportionately with the firing rate. However, as the bed cross section increases, the ratio of bed volume per unit of wall heat transfer surface area increases. Figure 12 shows how this ratio (or cross-sectional area per unit perimeter) increases with combustor cross-sectional area. Therefore, as the cross-sectional area increases for a unit of a given height, the amount of heat that can be removed through the waterwalls becomes a smaller fraction of the firing rate.

One method of obtaining the total required heat transfer surface is to increase the combustor height; however, the heat transfer surface that is introduced with added height is least effective at removing heat. This occurs because the rate of heat transfer varies with the solid suspension density and the solid suspension density in the YCEP combustor decreases rapidly with height until reaching a constant value in the upper furnace. This results in a more predictable heat absorption in the upper furnace. Furthermore, a lower density in the upper furnace results in less heat release, which is consistent with the lower heat absorption in the upper furnace.

In the YCEP ACFB design, the required amount of heat is removed through addition of a water-cooled, full division wall extending along the entire height of the combustor. This development introduces additional heat transfer surface throughout the entire furnace height. The division wall reduces the ratio of bed volume to the heat transfer surface area to a value that is typical of existing, smaller ACFB combustors as shown in Figure 12. Figure 13 compares the division wall design with alternative large scale ACFB combustor designs.

Other advantages of the full division wall include:

- *More uniform temperature distribution in the ACFB.* In comparison with a single chamber design, the division wall will help to produce more uniform temperatures across the ACFB due to the more even distribution of heat transfer surface throughout the combustor cross section.

- *Lower unit height.* A full division wall will allow combustor height to be constrained to that required for the cyclones rather than that required to achieve the necessary waterwall surface. Capital cost savings result by eliminating the need for additional structural steel, platforms and building enclosures. Reduced combustor height will also typically result in a lower stack height.

Special design features included in the proposed furnace division wall include:

- *Pressure Equalization Openings*

Figure 14 illustrates the design of the division wall openings. From the furnace floor to a height of about 12 ft., the fins between adjacent division wall tubes are removed. This allows the tubes to be bumped sideways, in-plane, to form multiple openings. Additional openings are also provided in the upper furnace over a 12 ft. span beneath the cyclone inlet. The openings in the upper furnace are located beneath the cyclone inlets to minimize lateral cross-flow of solids through the openings. The division wall openings function to equalize the pressure on both sides of the division wall.

The pressure equalization openings eliminate differential forces on the division wall, which simplifies the mechanical design. Also, a uniform air flow can be maintained across the width of the unit. Excess oxygen in the flue gas can be monitored at a common location at the heat recovery area exit and secondary air flow can be modulated to maintain the desired excess air level. Independent monitoring and modulating controls for each side of the division wall are not required.

- *Wear Resistant Design*

At the pressure equalization openings the division wall tubing is protected with the same high conductivity, erosion resistant refractory used on the lower furnace enclosure walls, roof, cyclone inlet walls, and the cyclones. The phosphate-bonded, high-alumina refractory which contains stainless steel reinforcing fibers is mounted on a high density stud pattern to a thickness of 1/2 inch. All the tubes are kept in plan so as not to protrude into the gas/solids flow stream for direct impingement. In this manner, the division wall will be no different from the water cooled enclosure walls which also have openings for solids cooler drains and fuel, limestone, and secondary air feeds.

- *Differential Thermal Growth*

The division wall is welded where it penetrates the air distributor and is held in tension by springs fixed at the top of the unit. A gap is provided between the division wall and the front and rear walls of the furnace. Since the division wall is heated on both sides while the enclosure walls are heated only on one side, the average division wall tube temperature will be slightly hotter than that of the enclosure walls. The support arrangement with no mechanical attachment to the enclosure walls allows both the division wall and the enclosure walls to independently grow downward at their respective rates. Foster Wheeler has designed numerous steam-cooled full division walls on pulverized coal fired steam generators. Steam cooled division walls have more stringent design requirements for differential thermal growth than do water-cooled division walls.

<u>Solids Mixing / Feed Distribution</u>

Solid mixing plays an important role in determining the performance of ACFB combustors. As the combustor scale increases, changes in several design parameters can affect how well the fuel and sorbent are distributed in the combustor. Data taken from other commercial ACFB plants will be presented to show that poor solid mixing can result in inefficient plant operation and higher plant operating costs.

Table 3 lists factors which are thought to influence the degree of solid mixing in the lower region of ACFB's. These factors are placed in three categories: (a) mixing due to external solid recirculation, (b) mixing due to internal solid recirculation, (c) mixing limitations caused by solids feeder configuration and boiler dimensions.

*Impact of Poor Solid Distribution*

Table 4 lists the impacts of poor solid mixing / fuel distribution. Nonuniform fuel distribution results in increased consumption of sorbent to achieve the same $SO_2$ emission level and may also increase the NOx generation rate. With increased NOx generation, $NH_3$ consumption increases to achieve the same level of NOx emissions and the $NH_3$ slip (flow of unreacted $NH_3$) also increases. When burning coals containing chlorine, greater NH3 slip increases the potential for $NH_4Cl$ formation. Poor fuel distribution will also lead to a reduction in combustion efficiency through increased hydrocarbon and CO emissions, and increased calcination heat losses. Nonuniform fuel distribution may lead to oxygen deficient reducing zones that cause bed agglomeration and slagging problems, and may produce local hot spots within the combustor.

*Factors Affecting Sorbent Utilization*

Table 5 lists a number of factors which are thought to influence sorbent utilization. The factors include: sorbent and fuel properties, solid mixing, combustor temperature, fuel and sorbent distribution, and cyclone grade efficiency. Important sorbent properties include the reactivity, friability, and feed size distribution. These properties will help determine how long the sorbent stays in the ACFB, how it is distributed between the lower and upper furnace, the extent to which the particle breaks apart to expose fresh CaO, and the reaction rate. Important fuel properties include: volatile content, reactivity, sulfur content and forms (organic, pyritic, sulfatic), and feed size distribution. The firing rate per fuel feeder will determine the local concentration of fuel at the feeder outlet. Increasing the firing rate per feeder will (for more volatile and reactive fuels) increase the reaction rate within this region, which will result in zones of low $O_2$ and high $SO_2$ gaseous concentrations and elevated local temperatures. Combustor temperature plays an important role due to the strong dependence of the sulfur capture reactions and combustion reactions on temperature. Sorbent distribution is also important to ensure a uniform concentration of unreacted CaO in the ACFB at the location where the $SO_2$ is released. The extent of solid mixing in the ACFB will help determine how well the fuel and sorbent are distributed. Finally, a cyclone with high capture efficiency for fines will retain the fine unreacted sorbent particles in the ACFB longer to react more completely. It should be noted that the YCEP ACFB boiler has a relatively short mixing zone, a distinct lower furnace bed that uses relativley coarse fuel and sorbent, as well as air swept fuel distributors, which promote more effective mixing in the furnace.

*Comparison of York Feed Distribution Design with other ACFB's*

Figures 15(a) and (b) compare the fuel feed distribution system designs of several existing ACFB's with the York design. In the first, the effectiveness of the fuel distribution systems are compared by representing each unit as a point on a graph of average firing rate per feeder (total firing rate/number of feeders) vs. upper combustor area per feeder. In the second, a comparison is made on a plot of average firing rate per fuel feeder vs. grid area per fuel feeder. ACFB combustor designs located toward the top and toward the right hand side of these figures should have greater mixing limitations and (other things being equal) would be expected to have less efficient $SO_2$ capture and higher limestone requirements. The shift in the relative arrangement of these units from Figure 15(a) to Figure 15(b) is due to different ratios of combustor area to grid area in different vendor's ACFB designs. The York(8) design with eight front wall feeders was improved upon by the addition of four back wall fuel and sorbent feeders. The improvement in the fuel distribution by adding four back wall feeders to the York ACFB design is evident by comparing the points labeled York(12), which includes the back wall feeders, and York(8) which does not.

Operating data taken at several other ACFB plants clearly shows that the fuel distribution can have a dramatic affect on the sorbent utilization efficiency (Ca/S ratio) while maintaining the same firing rate and sulfur capture. A parameter which quantifies how uniform or non-uniform the fuel is fed is simply the average firing rate per fuel feeder. Generally, the Ca/S ratio increases as the firing rate per feeder increases (or the number of feeders is reduced while maintaining the same total firing rate). Figure 16 shows sample data taken at an ACFB cogen facility. Ca/S molar ratio is plotted against average firing rate per feeder for two combustor temperatures and three different feeding configurations. In configuration (1) the fuel is evenly split between the two front wall and single loop seal feeder in the rear wall. In configuration (2), the fuel flow is split between the two front wall feeders. And in configuration (3), 100% of the fuel is fed through the rear wall loop seal. The unexpected drop in Ca/S ratio upon changing from configuration (2) to (3) is thought to be due to the much improved solids mixing and distribution resulting with loop seal feeding due to the large momentum flow of the recycle solids. This data clearly shows the strong influence that fuel distribution is expected to have on sorbent consumption. The YCEP design includes a return channel with multiple openings communicating with the combustor for optimal distribution of the return solids.

This and other data on the reduction in Ca/S ratio resulting from improved fuel distribution in several ACFB units burning similar types of fuel was used to estimate the potential reduction in Ca/S ratio due to addition of the back wall feeders to the YCEP project. A similar reduction in Ca/S on the order of 20-30% would be expected.

Cyclone Separator Design and Configuration

Another design issue important to the successful scale up of ACFB combustors is the design of the cyclone gas-solid separation system. As the size of the combustor increases, the mass flow of gas and solids exiting the top of the combustor to the cyclones increases proportionally (given same particle size, combustor height, etc.). One method of performing this separation with the increased flow of particle-laden gas is to increase the size of the cyclone. Unfortunately, as the cyclone size (diameter) increases the centrifugal force field is reduced (at the same gas inlet velocity) and the particle collection efficiency deteriorates. In the absence of high solids collection efficiency, smaller sorbent, carbon, and ash particles escape through the cyclone rather than being recycled to the combustor with the cyclone underflow. This would result in inefficient fuel and sorbent utilization and a reduction in inventory of particles capable of circulating and transferring heat. Another drawback of increased cyclone size is that the increased cyclone height may dictate increased combustor height for the solids recirculation system to function properly.

To enable high gas-solid separation efficiency with the YCEP ACFB boiler design the size of the cyclones was held similar to that utilized in smaller units. However, to accommodate the increased gas flow rate the number of cyclones was increased. The YCEP boiler will utilize four cyclones arranged as shown in Figure 17.

The cyclone separator designs features steam cooling and is an integral part of the steam superheat circuit. Steam cooling of the cyclones offers the following advantages:

- Faster unit start-up
- Reduced heat losses
- Reduced requirements for high-temperature refractory ductwork and expansion joints

**Technical Innovation**

The following section describes several innovative features of the ACFB system design:

INTREX™ Integrated Recycle Heat Exchanger

The INTREX™ heat exchanger is simply an unfired fluidized bed heat exchanger with a non-mechanical means for diverting solids. It will take advantage of the high heat transfer coefficients for tubes immersed in bubbling fluidized beds and will also operate advantageously with fine (200 micron) particles. Due to the fine recycle solids and the low fluidizing velocities (0.5 to 1.5 ft/s), tube erosion will not be a concern. The INTREX™ heat exchanger allows for part of the heat released in the combustor to be removed outside of the combustor. This method of heat removal will eliminate the need for excessively tall combustors or the need to install furnace panels which protrude into the erosive flow in the combustor and are subject to excessive wear.

The INTREX™ heat exchanger will be enclosed by the same water-cooled membrane construction used in the furnace. The integrated configuration will allow it to grow downward with the rest of the boiler steam/water pressure parts, minimizing differential thermal movement. Placement of serpentine superheater coils within the recirculated solids flow path enables the entire reheater to be located in a conventional parallel pass heat recovery area. Final main steam temperature will be controlled by spray water attemperation, while reheat steam temperature will be controlled by gas flow proportioning in the heat recovery area.

FWEC has extensive experience in the design of atmospheric bubbling fluidized bed (BFB) heat exchangers from the 46 BFB steam generators that it has designed and put into operation. Scale up of the INTREX™ BFB is not an issue since the main cell in the 130-MW Northern States Power Black Dog unit is about four times greater in plan area than the largest INTREX cell in the YCEP ACFB. The INTREX™ heat exchanger will be divided into four cells.

## DOE Clean Coal I Demonstration Tests

In the demonstration test program proposed to the U.S. Dept. of Energy, a series of demonstration tests were specified to evaluate FWEC's ACFB technology for large-scale electric utility applications. The goal of the proposed test program is to determine the impact of important operating parameters and fuel characteristics on the design, operation, and performance of the ACFB facility and the costs of electric power production. Since the proposed 250 $MW_e$ ACFB will become the largest single ACFB boiler in operation and even larger capacity units are anticipated for electric utility applications, the results of this test program will be important to both the technology evaluation and the design of larger utility-scale ACFB's.

Specifically, this demonstration program is designed to provide the following important information:

- Demonstrate unit start up and shut down capabilities and provide data and experience on ACFB boiler operation during these transients.
- Demonstrate ACFB boiler dispatching capabilities and constraints.
- Demonstrate ACFB boiler operation at full-load conditions for extended periods and continuous operation at part-load conditions.
- Provide quantitative results from a systematic study on the effects of important operating parameters and fuel characteristics on boiler performance which will aid in the optimum economic design and operation of future units.
- Identify constraints governing fuel selection based on test results from four different fuels.
- Provide guidelines for inspection and maintenance along with information on maintenance costs.

Included in the test program are specific operating tests to evaluate the effects of the following operating parameters on ACFB performance:

- Fuel size and quality
- Sorbent size and quality
- Fuel and sorbent rates
- Combustor temperature
- Excess air
- Primary/secondary air ratio

Specific boiler performance parameters to be quantified include:

- Boiler thermal efficiency
- Steam/Electrical Generation Capacity
- Ability to control steam temperature and pressure
- Ash production and quality
- Bed ash / fly ash split
- Unburned carbon losses in bed and fly ash
- Stack emissions: $NO_x$, $SO_2$, CO, VOC and particulate
- Power consumption of auxiliary equipment
- Percent $SO_2$ capture and Ca/S ratio
- Control of bed inventory
- Combustor temperature profile

Tests are proposed for four different coals: the design coal (basis for combustor design) and three test coals having different properties from the design coal. The purpose of performing tests with coals having properties which differ from the design coal is to determine what range of coal properties can be utilized and the impact of fuel characteristics on the performance and operating economics of the ACFB. The same sorbent material would be used throughout all of the tests.

In addition to performing tests at 100% maximum continuous rating (MCR), tests would be performed to demonstrate operation of the boiler and other ACFB system components during start-up, shutdown, and dispatch of the facility. To demonstrate the capability of the system, a 30-day test with the boiler operating at a minimum of 96% MCR is proposed.

## Environmental Considerations

The YCEP Cogeneration facility will be equipped with the necessary air pollution control equipment to meet the BACT determination.

Air Quality Controls

Under the Clean Air Act Amendments of 1990, the York County, PA area is determined to be marginally non-attainment for ozone. Other than ozone, there are no known ambient air quality problems in the immediate project vicinity. Sufficient prevention of significant deterioration (PSD) increment is available for both $SO_2$ and $NO_x$ which will allow for approval of the air permit. Since the VOC emissions from the facility will be greater than 50 TPY, some VOC offsets will be required to comply with the ozone non-attainment.

Based on recent PSD air quality permits issued by PA Department of Environmental Resources (DER) Bureau of Air Quality for coal fired projects, the following minimum technical criteria are anticipated for the YCEP Cogen facility:

- Required $SO_2$ reduction will be 92% or greater. This level of sulfur capture can be achieved through addition of sorbent material to the ACFB.
- Required $NO_x$ reduction will be 50% or greater. This level of $NO_x$ abatement can be achieved through use of selective non-catalytic reduction with ammonia.
- Particulate emissions must not exceed 0.015 lb/MM BTU. Baghouse technologies will meet this requirement.
- The facility will be equipped with a continuous emissions monitoring system (CEMS) to monitor opacity, $SO_2$, $NO_x$, $CO_2$, or $O_2$, and flue gas flow rate.

Solid Waste Management

The combustion of coal in the ACFB will result in byproduct ash generation. The fly and bed ash byproduct materials are dry and inert, consisting of a heterogeneous mixture of coal ash, calcium sulfate and calcium oxide. During full operation, a significant quantity of ash byproduct will be generated. Pilot plant tests are currently being conducted to quantify expected volumes of ash byproduct requiring disposal. Ash byproduct will be temporarily stored on-site in enclosed silos having 2000 tons storage capacity, then transferred into enclosed 20-ton trucks for transport to a location for beneficial reuse. Because of the ACFB ash byproduct's high lime content, its concentrations of silicon, aluminum, and iron, and its pozzolonic properties, beneficial uses for the material can be found; these include sludge stabilization agents, agricultural soil additives, and road bed aggregate. Air Products has investigated and found viable ash byproduct uses for the ash produced at two existing facilities which Air Products owns and operates.

Waste Water Disposal

The YCEP project is designed as a low-discharging facility, through the efficient recirculation and reuse of water in the process system. Waste water will be disposed of in two different means. The majority of facility wastewater will be discharged to Cordorus Creek from a proposed new point source location. Flows to be discharged in this manner include utility and process streams such as cooling tower blowdown, plant maintenance wastes, and storm water runoff. The resulting discharge will be raw makeup water within which the naturally occurring minerals (e.g., calcium, magnesium, sulfate) have been concentrated due to the evaporation of water in the steam process and cooling water systems. Remaining facility waste water (domestic sewage and demineralizer regeneration waste) will be treated at the York County Wastewater Treatment Plant. Prior to discharge of these waste water streams, they will be combined in a sump and adjusted for pH. The treated stream will then meet or exceed the existing York County Wastewater Treatment Plant statutes and regulations, as well as BAT requirements.

## Commercial Feasibility

Market Potential

The U.S. electric utility industry currently expects a market to develop, beginning in the next 10 years, for 100- to 300 MWe power generation units as add-on capacity and for repowering or retrofitting aging power plants. The YCEP project plant, rated at 227 MWe net, is sized to demonstrate FWEC's ACFB technology near the high end of this range. The NISCO (120 MW) project demonstrated FWEC's ACFB technology for petroleum coke at the lower end of this scale. The design, construction, testing, scale-up success, and documentation of both costs and operational experience with the YCEP Cogen project will provide utilities with information they will need to plan to replace or retrofit existing units, or to install new generating capacity in the near future.

The YCEP Cogen project represents a substantial scale-up from the largest operating single combustor ACFB. Upon completion of design, construction and start-up of the YCEP Cogen facility, the Clean Coal Technology 1 Demonstration Program will provide a database on the operating performance and cost from this unit. These tests will confirm performance specifications, determine operating costs, and determine operating conditions which minimize gaseous emissions. A database for the component material performance will also be compiled during this test period. This Demonstration Test Program will provide utilities with sufficient information to enable utilities and independent power producers to fairly and accurately evaluate

FWEC's ACFB technology and permit further application of this technology. Since initial commercial orders would be very similar in design to the YCEP ACFB boiler, this would save engineering, design, and construction time and help reduce costs and expedite commercialization.

## Conclusion

The systematic and collaborative approach followed by Air Products and Foster Wheeler Energy Corporation in the ACFB design and scale-up for the YCEP project will help guarantee the success of this important demonstration project. The pilot plant test program being conducted will serve to guarantee the performance of the commercial ACFB cogen plant. Furthermore, the review of the scale-up issues and the integration of components in the system was completed and new innovations were incorporated into the ACFB design. As a result of this development effort, we hope to demonstrate that FWEC's ACFB technology can be utilized at the utility scale (250 MWe) to reliably, economically and efficiently produce electricity and steam from U.S. coal reserves while having minimal impact on our environment.

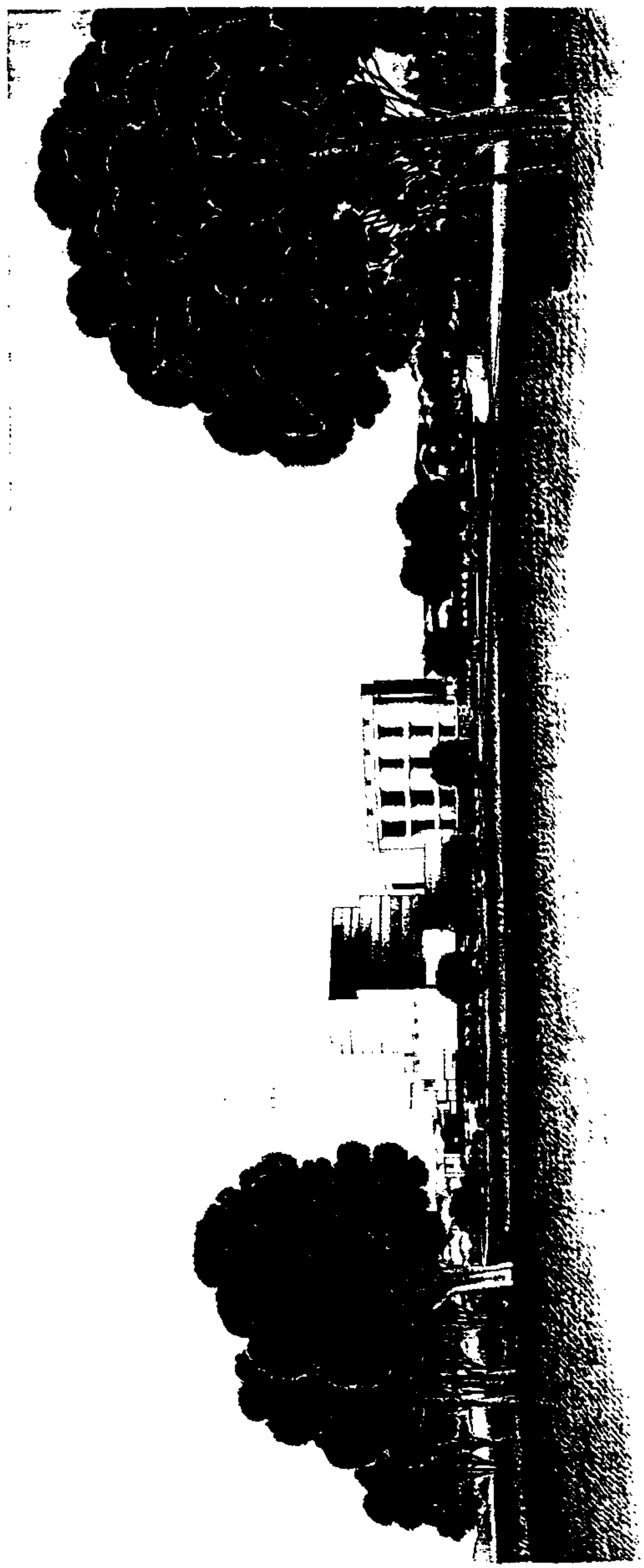


Figure 1. York County Energy Partners Proposed Cogen Facility.

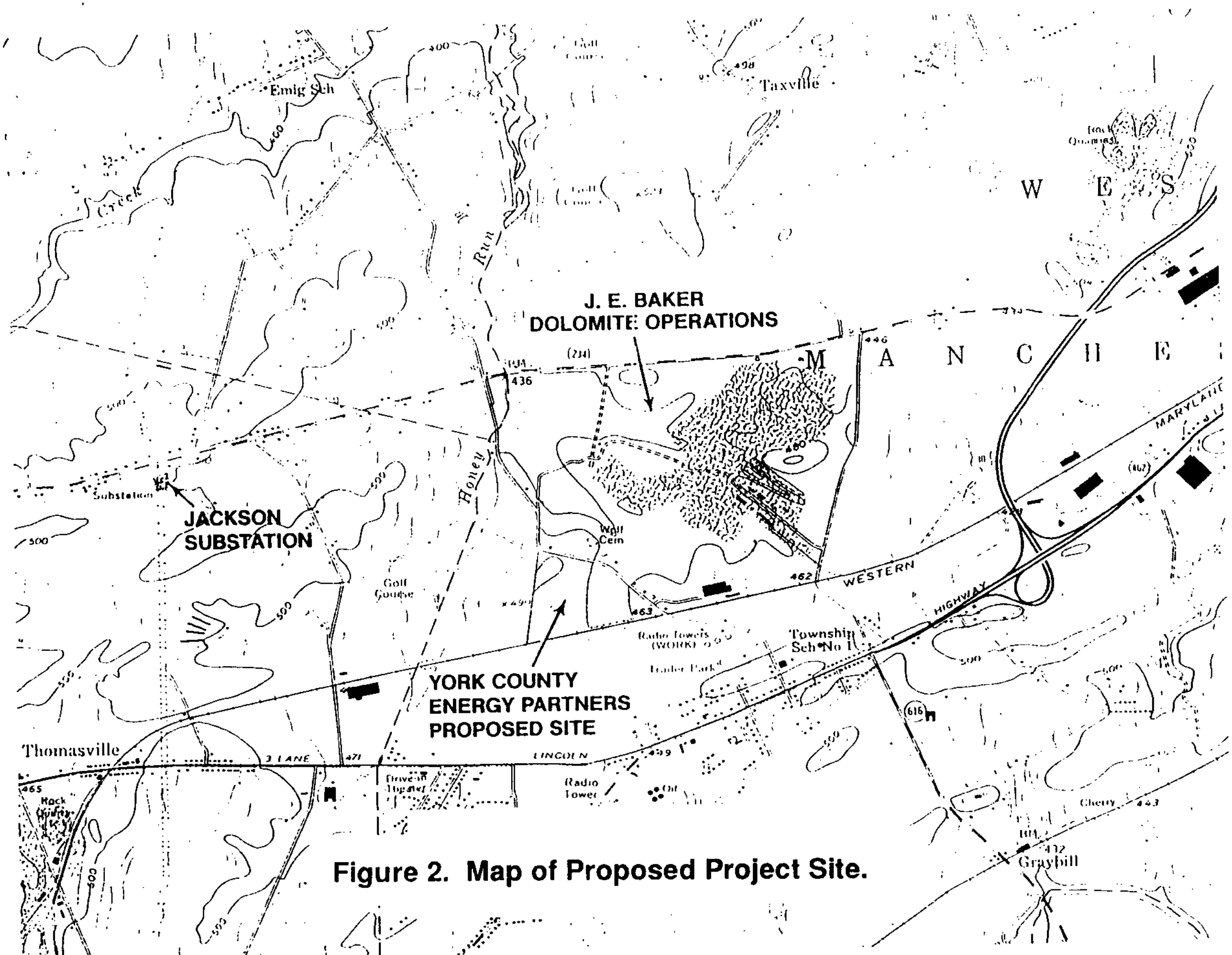



Figure 2. Map of Proposed Project Site.

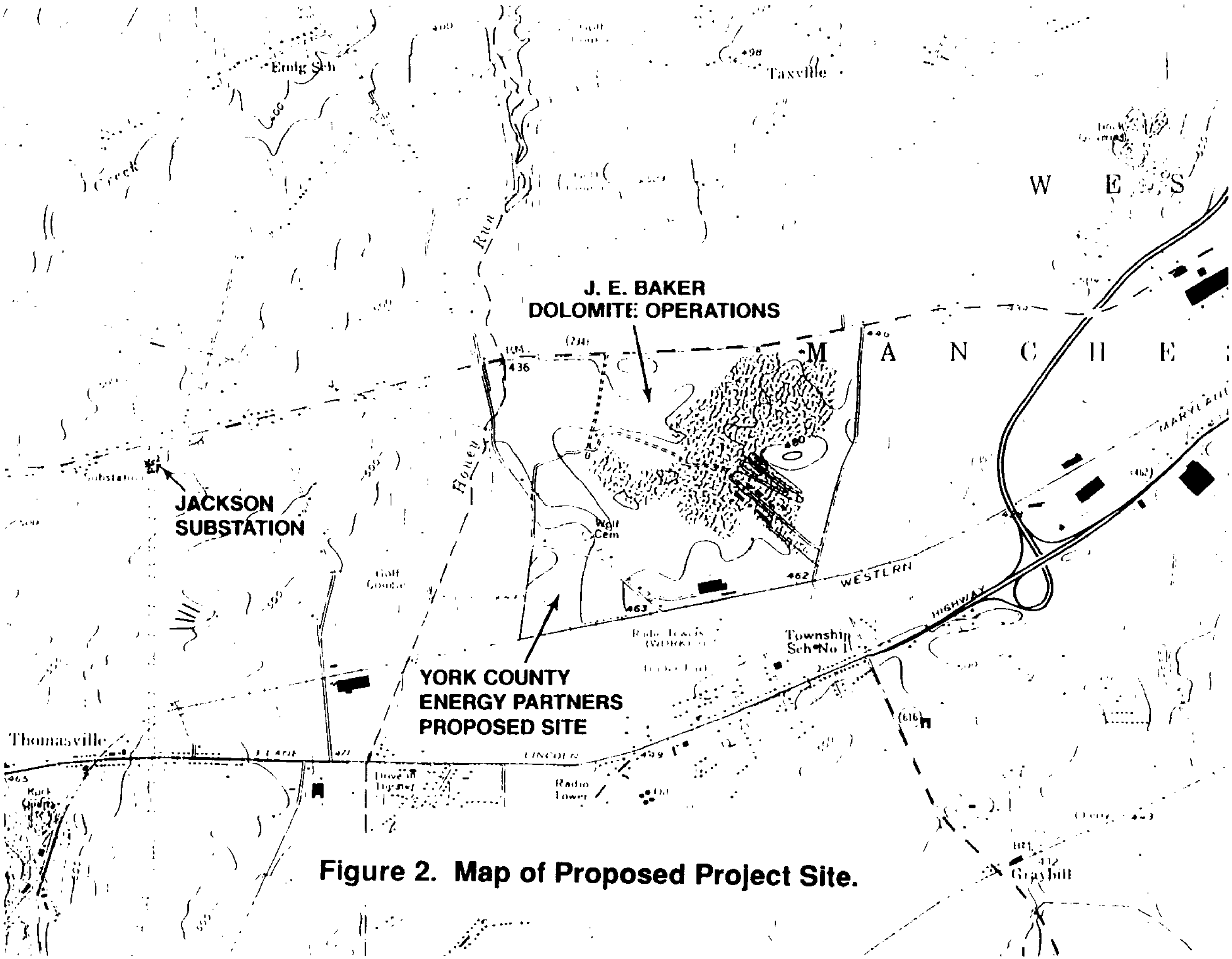



Figure 2. Map of Proposed Project Site.

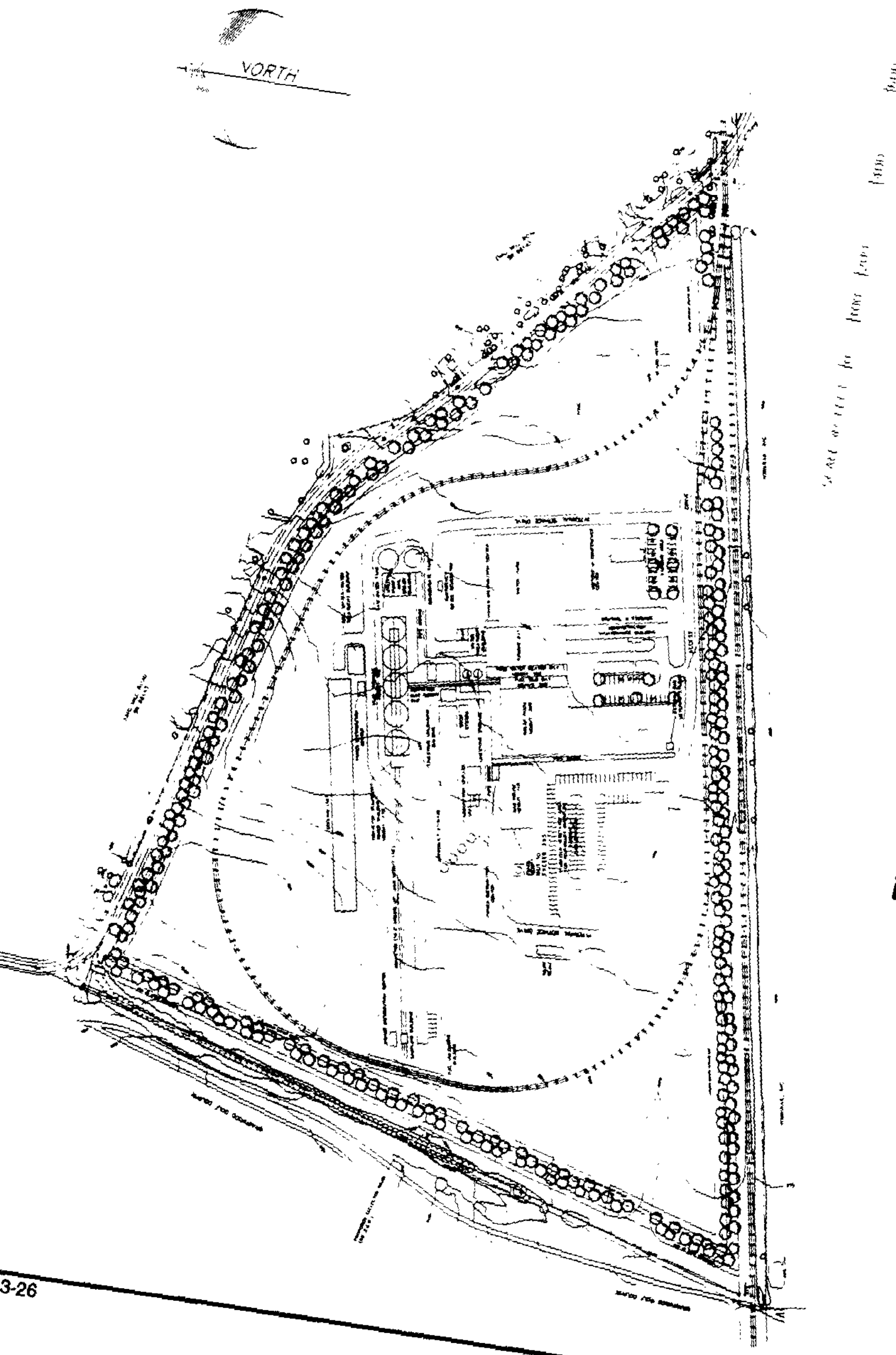


Figure 3. Plot Plan for YCEP Facility.

## Table 1
## YCEP Project Summary

| | |
|---|---|
| Title: | York County Energy Partners Clean Coal Technology Round I Cogeneration Project |
| Proposer: | Air Products & Chemicals, Inc. |
| Location: | York County, PA |
| Technology: | Atmospheric Circulating Fluidized Bed Combustion |
| Applications: | Utility and Industrial Electric Power/Steam Generation, Repowering Existing Boilers or New Plants |
| Fuel: | Low Sulfur Western PA, MD, or W. VA Bituminous Coal |
| Size: | 227 MWe net to Met-Ed 1,725,000 PPH/2500 psig/1005°F Main Steam, 1,400,000 PPH/442 psig/1005°F Reheat Steam |
| Steam Host: | J. E. Baker Co., York, PA 50,000 PPH Steam |
| Project Cost: | Greater than $ 300 Million |
| DOE Funding: | $ 75 Million |

## Table 2
## York County Energy Partners Project Schedule

| Major Milestones | Start Date | Completion Date |
|---|---|---|
| Submit Proposal | | Oct., 1991 |
| Negotiate Power Purchase Agreement | Dec. 10, 1991 | Mar. 6, 1992 |
| PUC Approval | | Nov. 1, 1992 |
| Environmental Permitting | Dec. 2, 1991 | Dec. 15, 1993 |
| Close Financing | | Dec. 16, 1993 |
| Prelim. Engineering | Oct. 1, 1992 | Dec. 31, 1993 |
| Design Engineering | Mar. 29, 1993 | Apr. 14, 1994 |
| Equipment Procurement | Feb. 18, 1992 | Feb. 14, 1995 |
| Boiler Steel and Boiler Erection | Sep. 1, 1994 | Sep. 13, 1996 |
| Initial Plant Check Out | May 21, 1996 | Sep. 24, 1996 |
| Synchronize with Grid | Feb. 7, 1997 | Feb. 13, 1997 |
| Performance Test | Feb. 14, 1997 | Feb. 28, 1997 |
| Commercial Operation | | Mar. 3, 1997 |

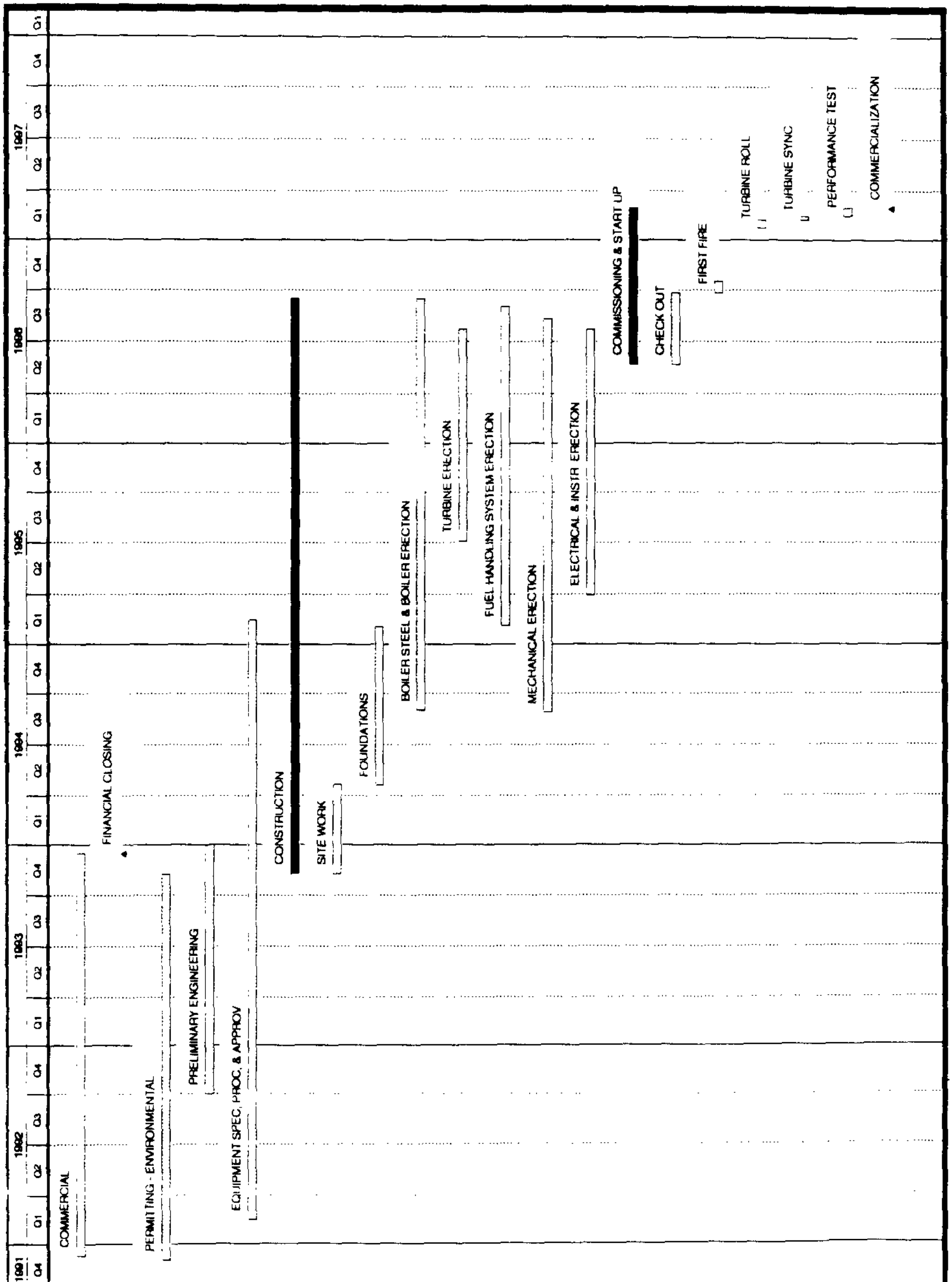



**Figure 4. YCEP Project Schedule.**

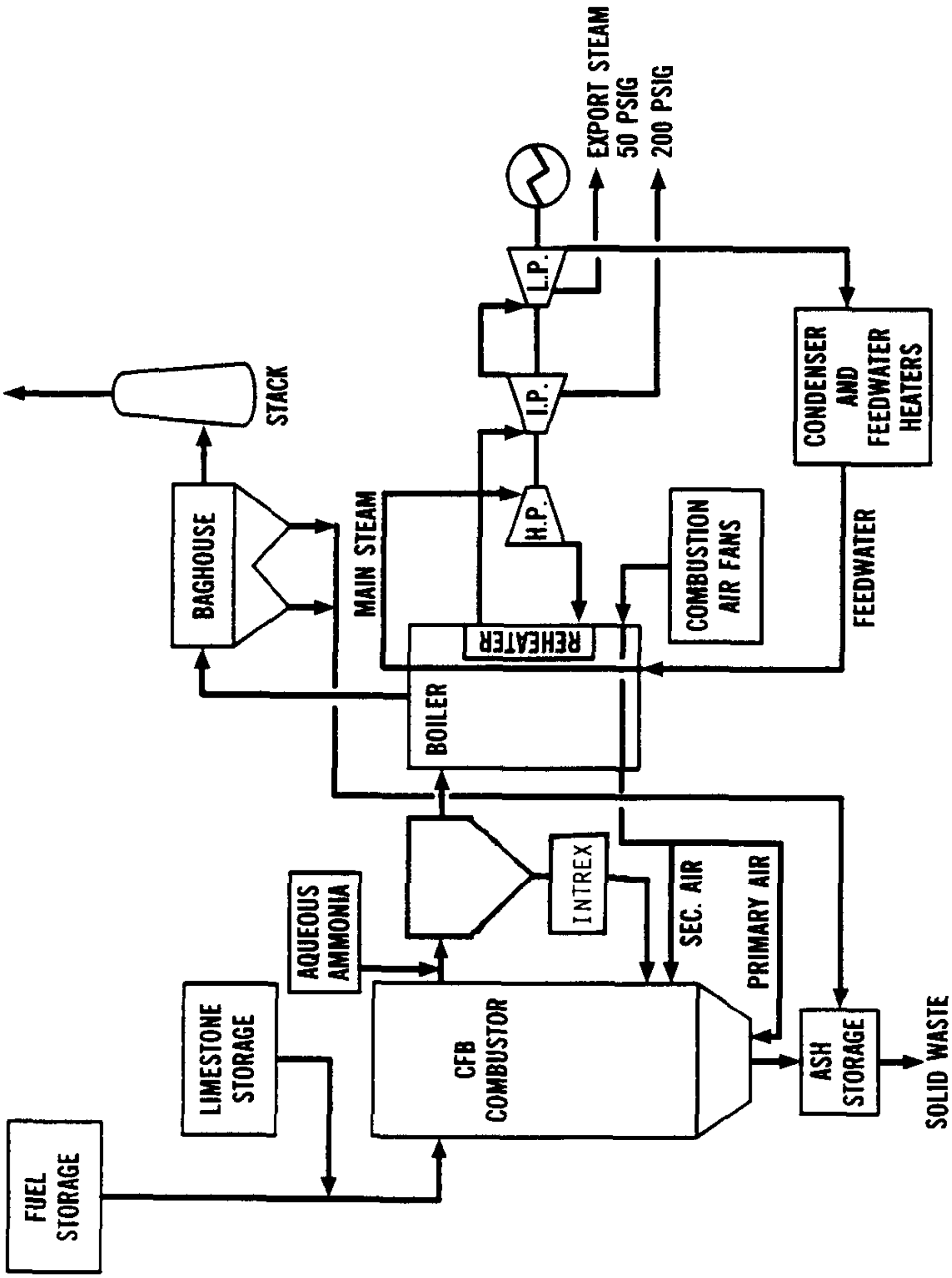



**Figure 5. Process Flow Digram for YCEP Cogen Facility.**

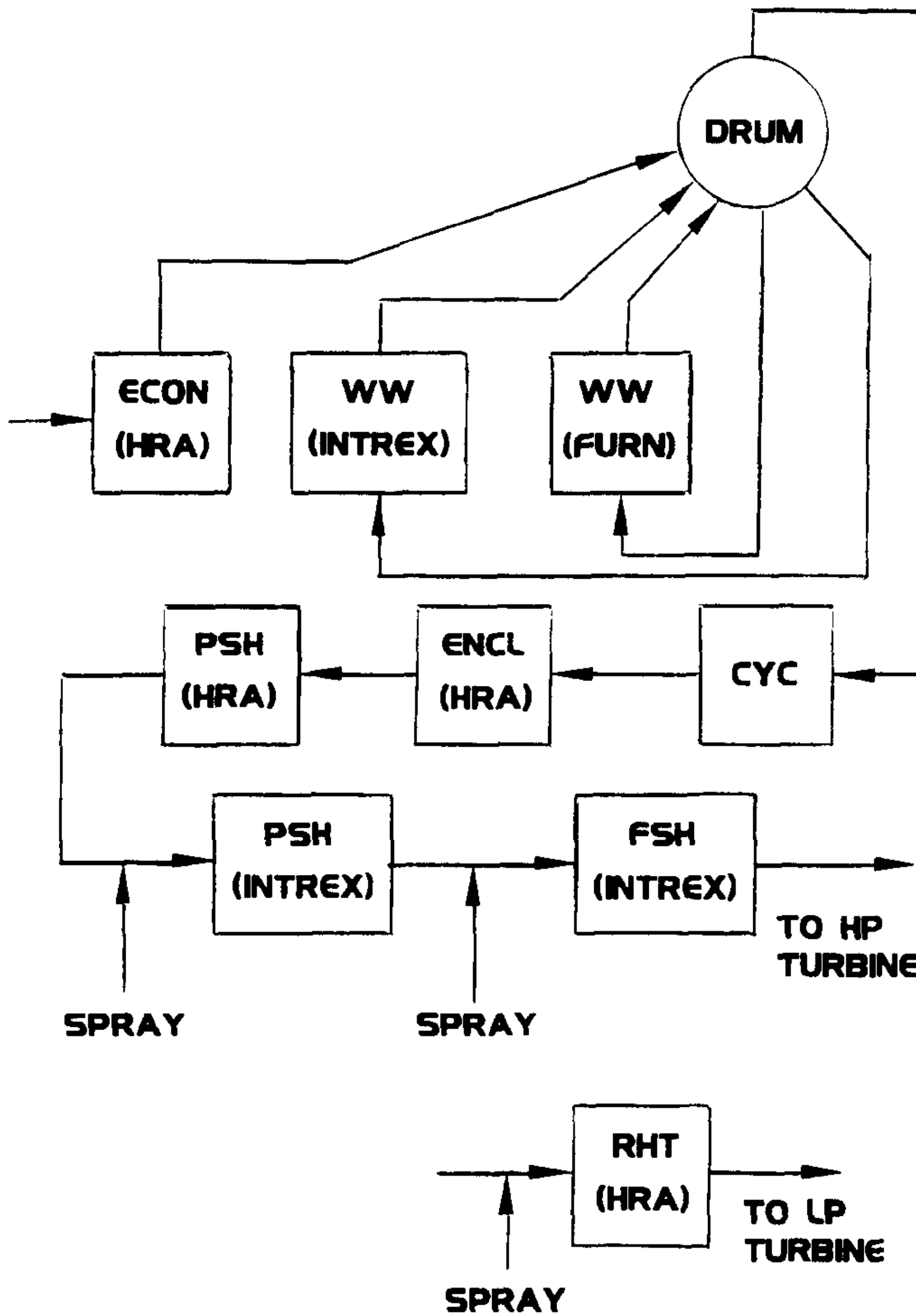



Figure 6. Steam/Water Circuitry.

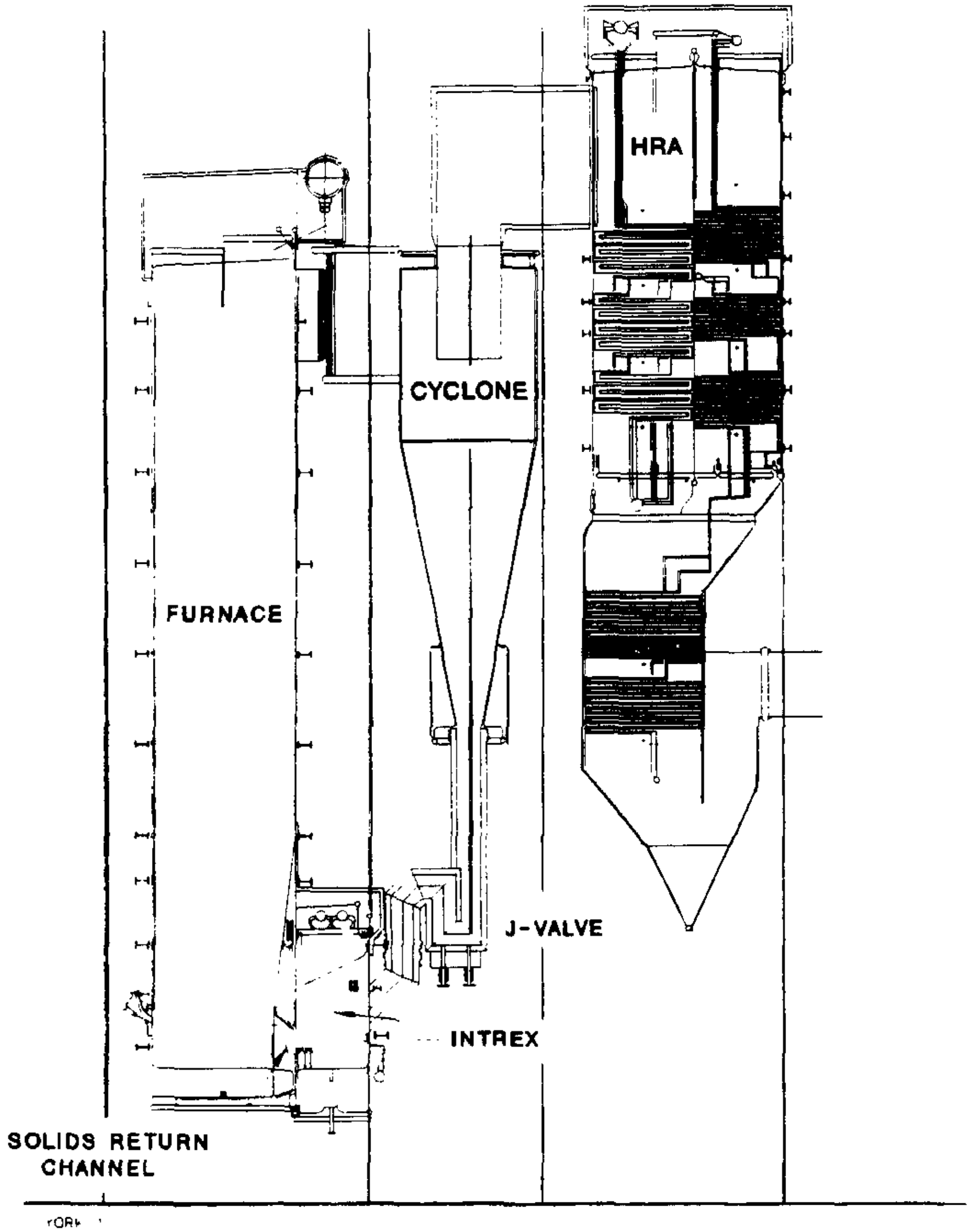



Figure 7. ACFB Steam Generator for Reheat Applications.

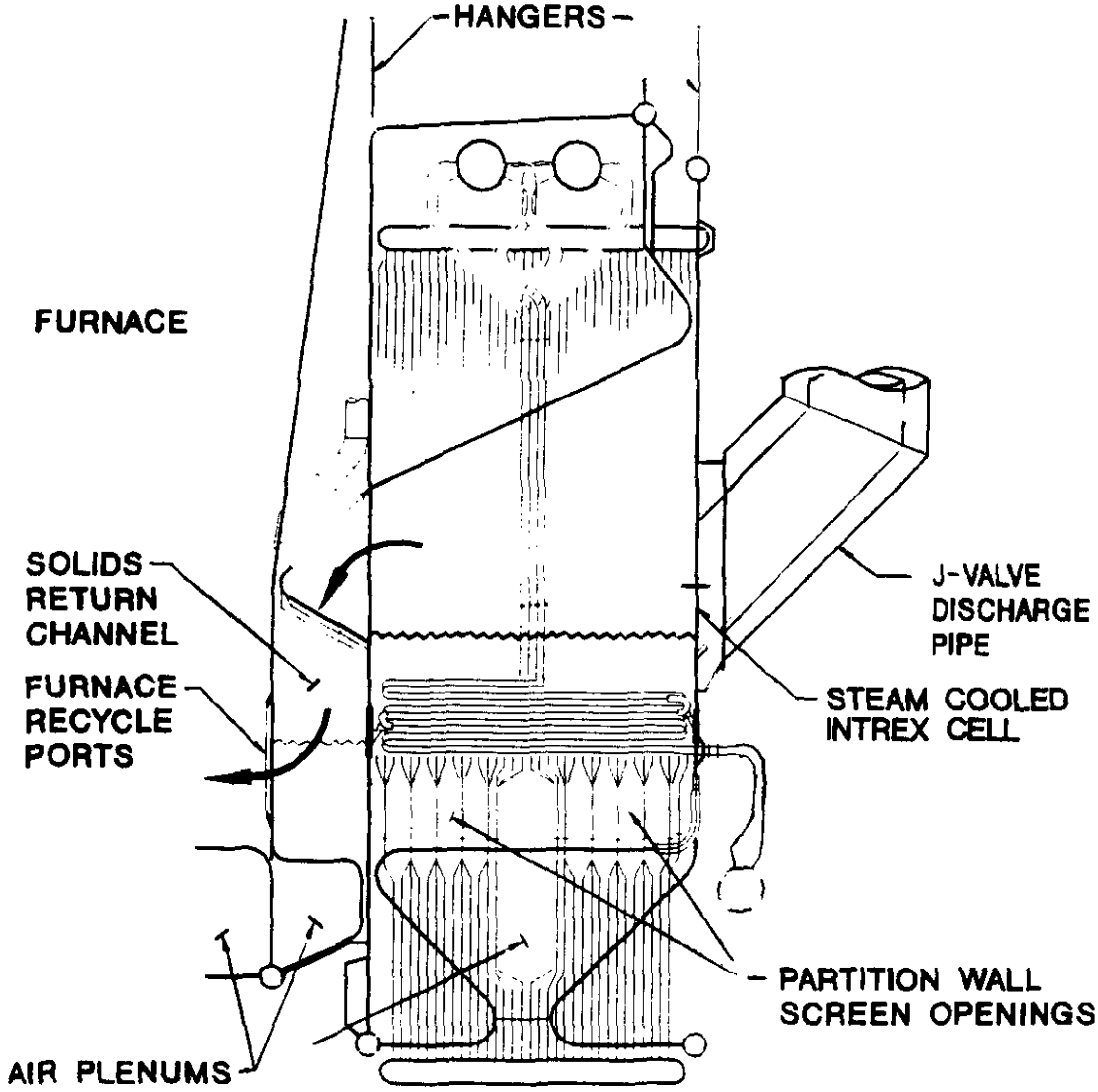



Figure 8. INTREX.

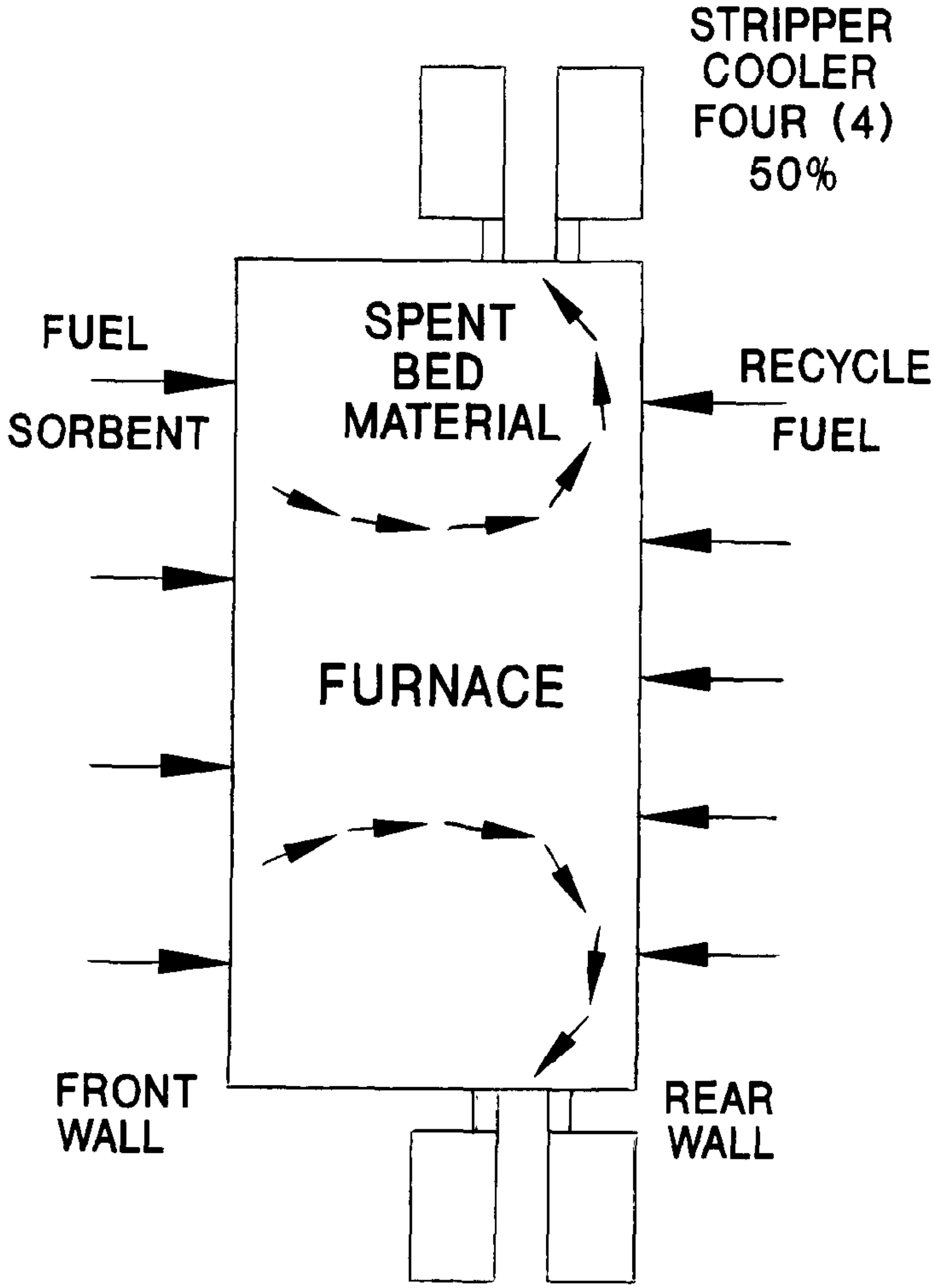



Figure 9. Solids Flow to Cooler.

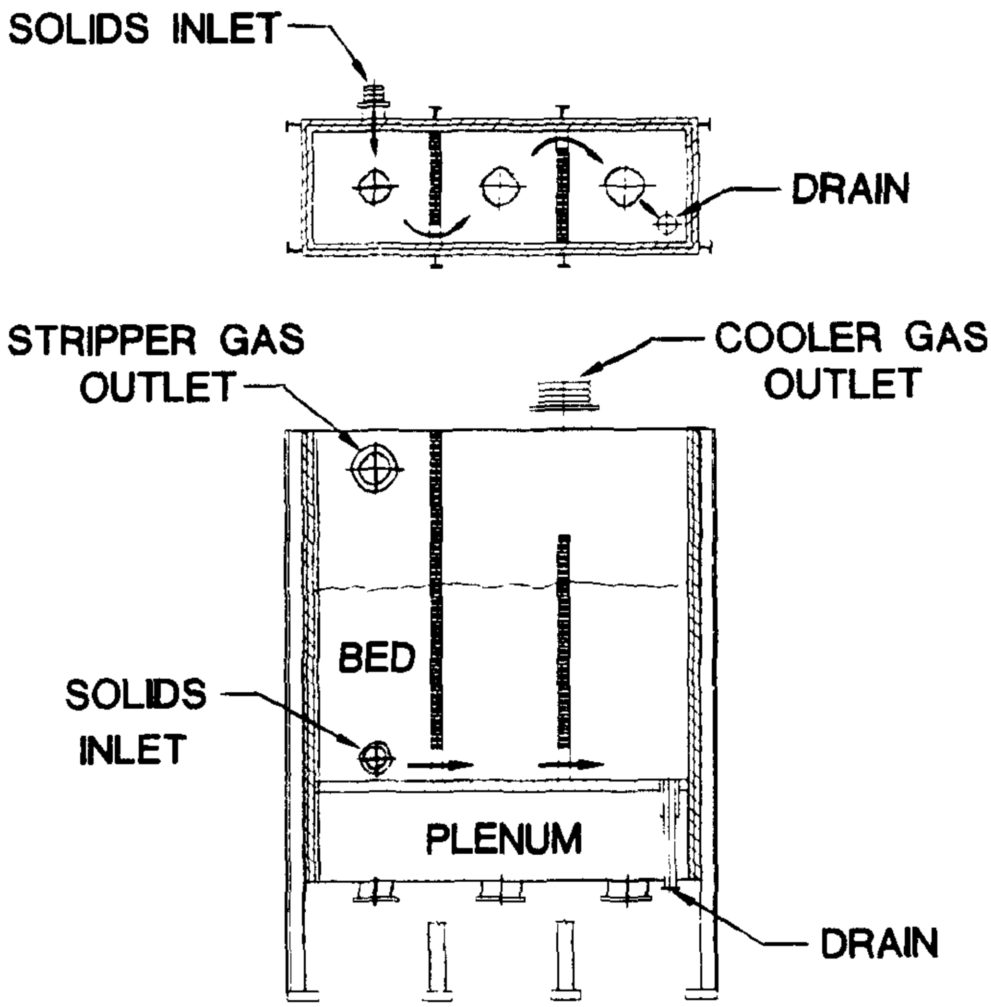



Figure 10. Stripper Cooler.

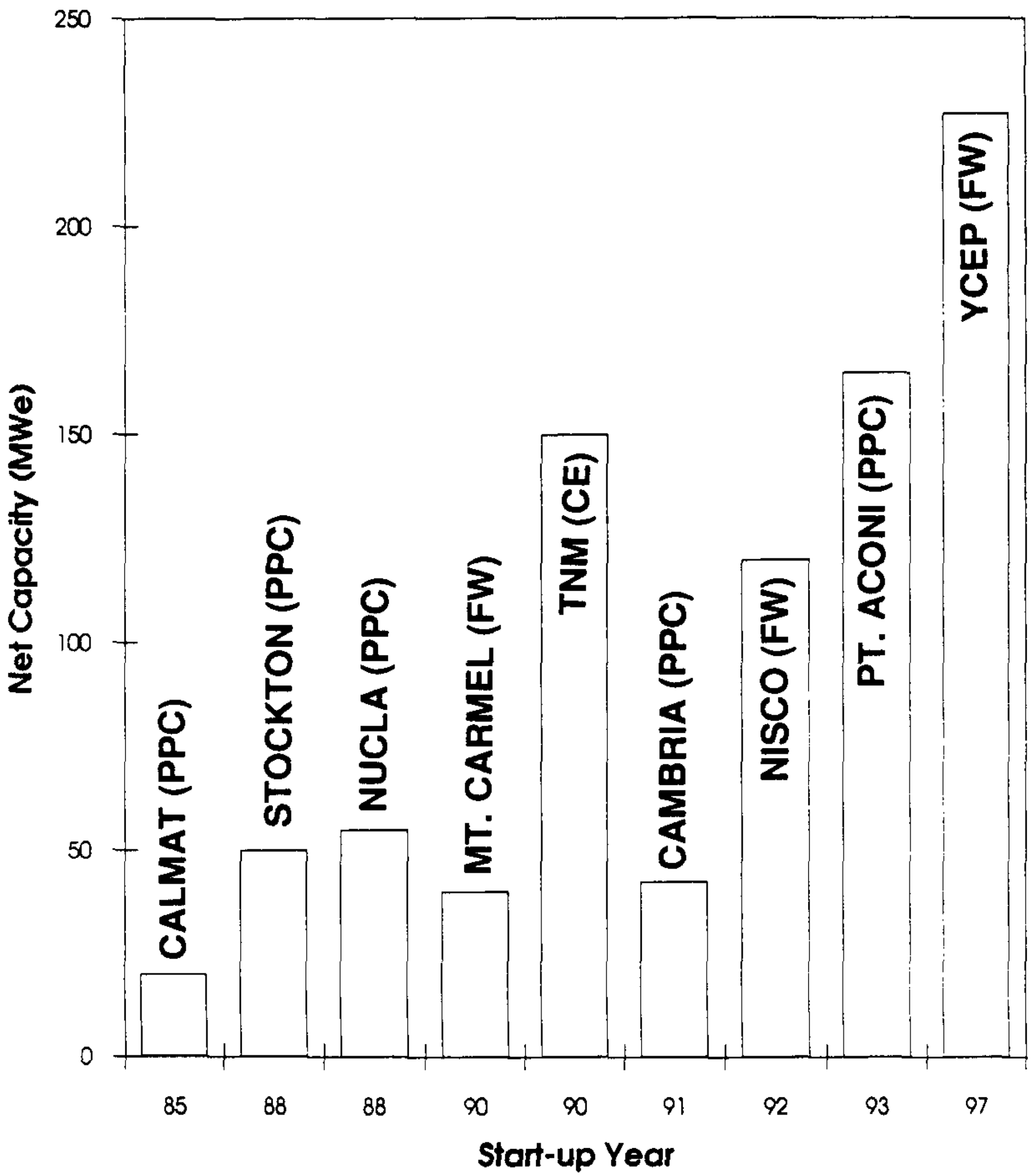



Figure 11. Evolution of ACFB Technology.

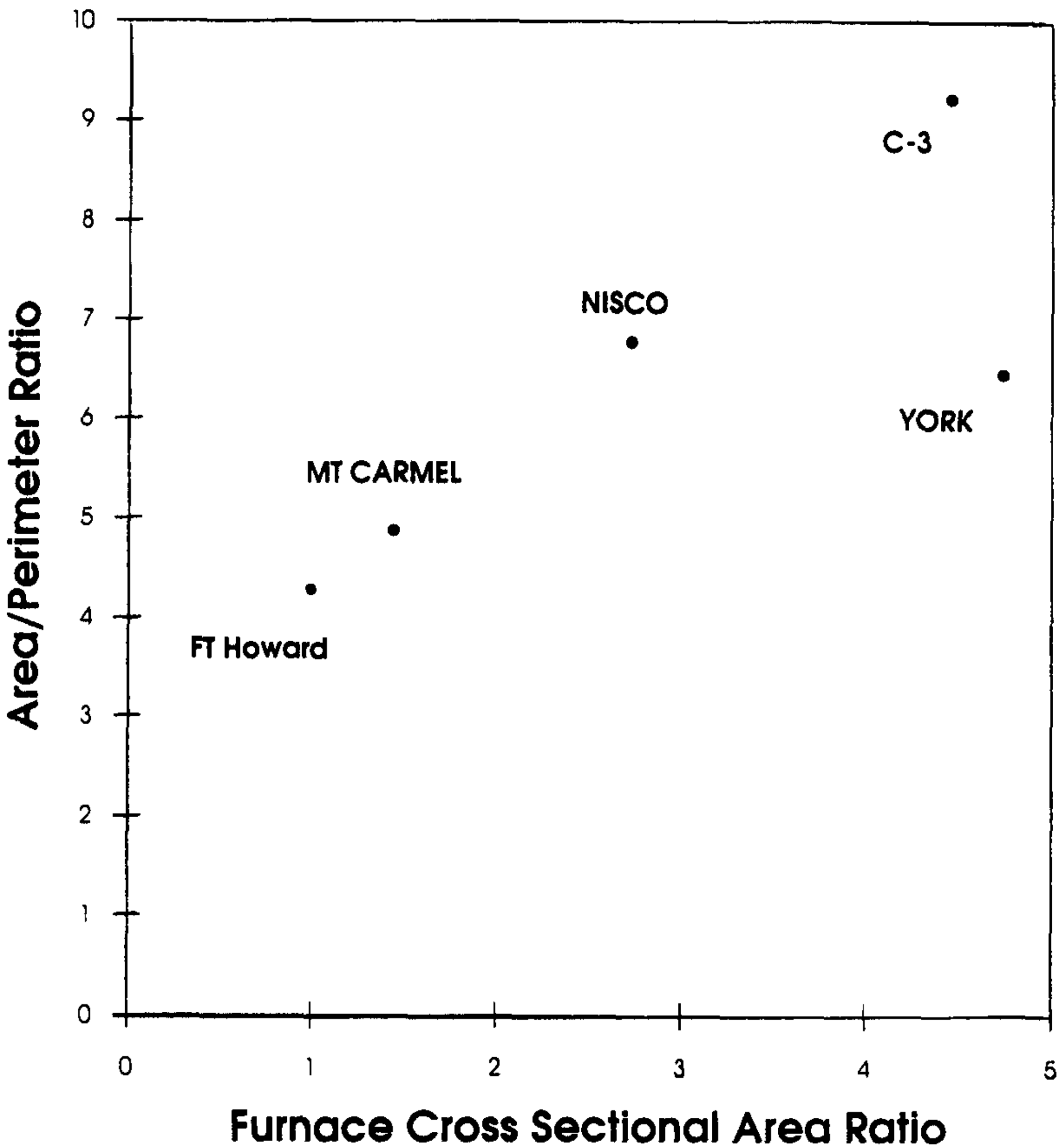



Figure 12. Division Wall Improves Furnace Area/Perimeter Ratio.

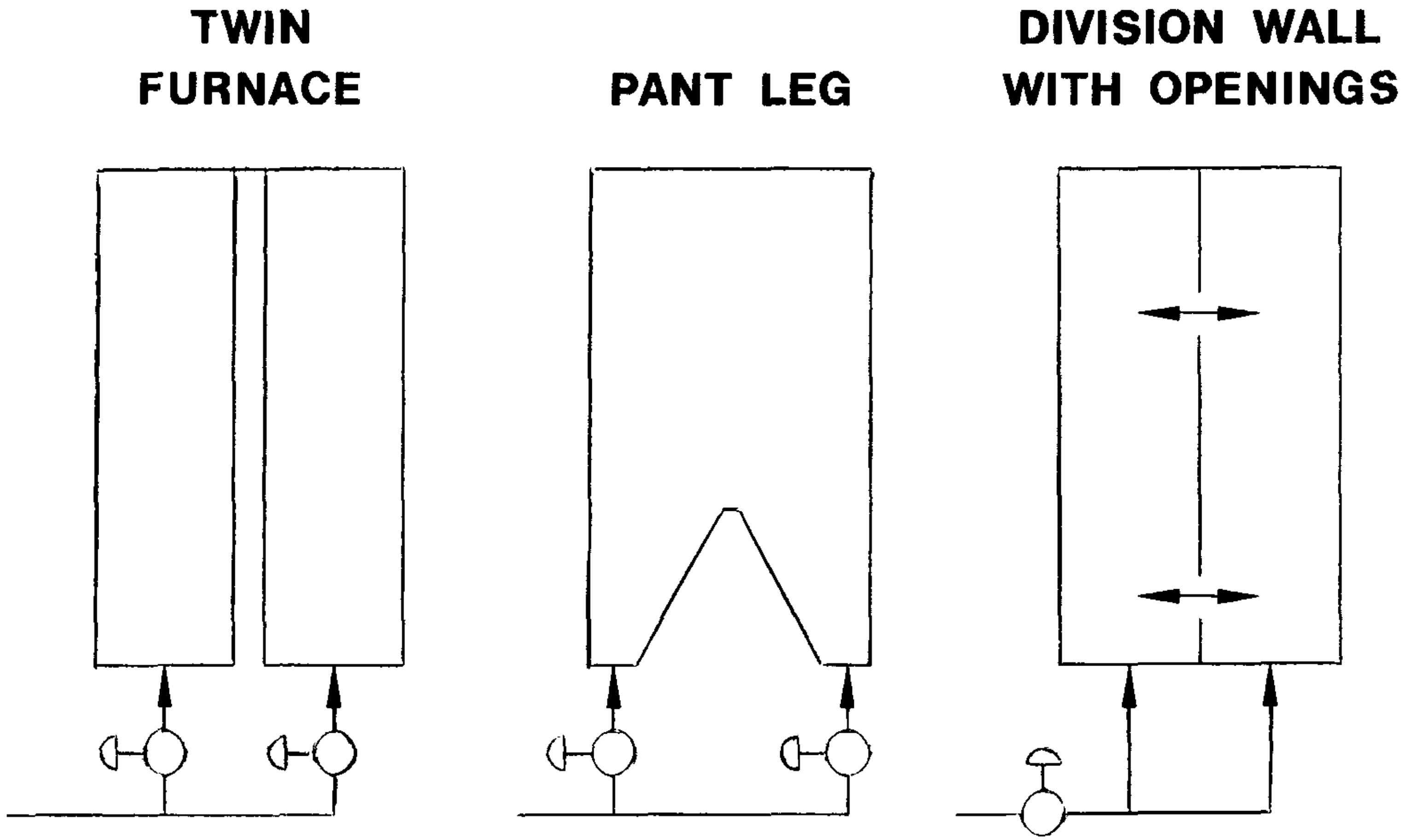



Figure 13. Large Scale ACFB Furnace Arrangements.

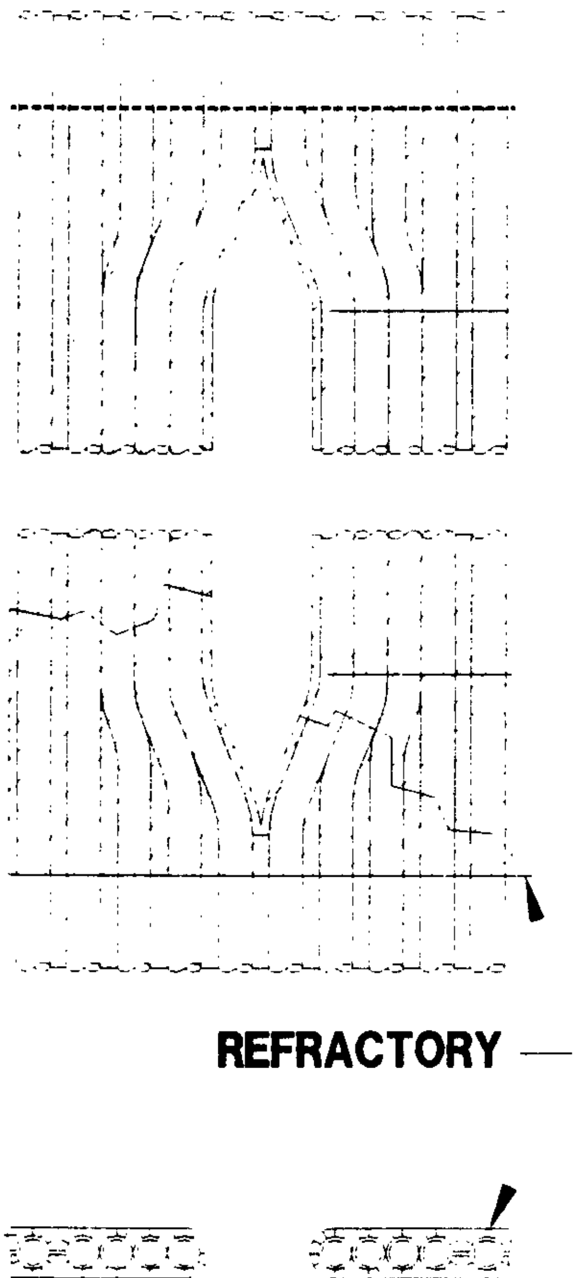



Figure 14. Division Wall Opening.

## Table 3

## Factors Affecting Solid Mixing

I External Solid Recirculation

- Gas Velocity at Grid
- Fine Solids Residence Time Based on External Recirculation
- Solid Particle Size (Attrition, Cyclone Efficiency, Feed Size)
- Momentum of Return Solids Flow and Number of Return Points
- Primary/Secondary Air Split
- Secondary Air Elevation

II Internal Solid Recirculation

- Fine Solids Residence Time Based on Internal Recirculation and Retention in Lower Bed
- Combustor Geometry - Front/Back Wall Taper
- Grid Nozzle Design

III Solid Feed Configuration

- Feeder Location (Wall, Loopseal)
- Combustor Depth
- Feeder Spacing

## Table 4

## Impact of Poor Solid Mixing

- Limestone Consumption <u>Increases</u>
- NOx Generation <u>Increases</u>

    $NH_3$ Consumption <u>Increases</u>

    $NH_3$ Slip <u>Increases</u>

    $NH_4Cl$ Formation Potential <u>Increases</u>

- Combustion Efficiency <u>Decreases</u>

    Agglomeration

    Slagging

## Table 5
## FACTORS AFFECTING SORBENT UTILIZATION

- Sorbent Properties
  - Reactivity
  - Friability
  - Feed PSD
- Fuel Properties
  - Volatility
  - Reactivity
  - Sulfur content & forms
  - Feed PSD
- Combustor Temperature
- Firing Rate per Feed Point
  - Local O2 Concentration
  - Local SO2 Concentration
  - Local Temperature
- Sorbent Feed Distribution
- Solid Mixing in Lower Furnace
- Cyclone Efficiency

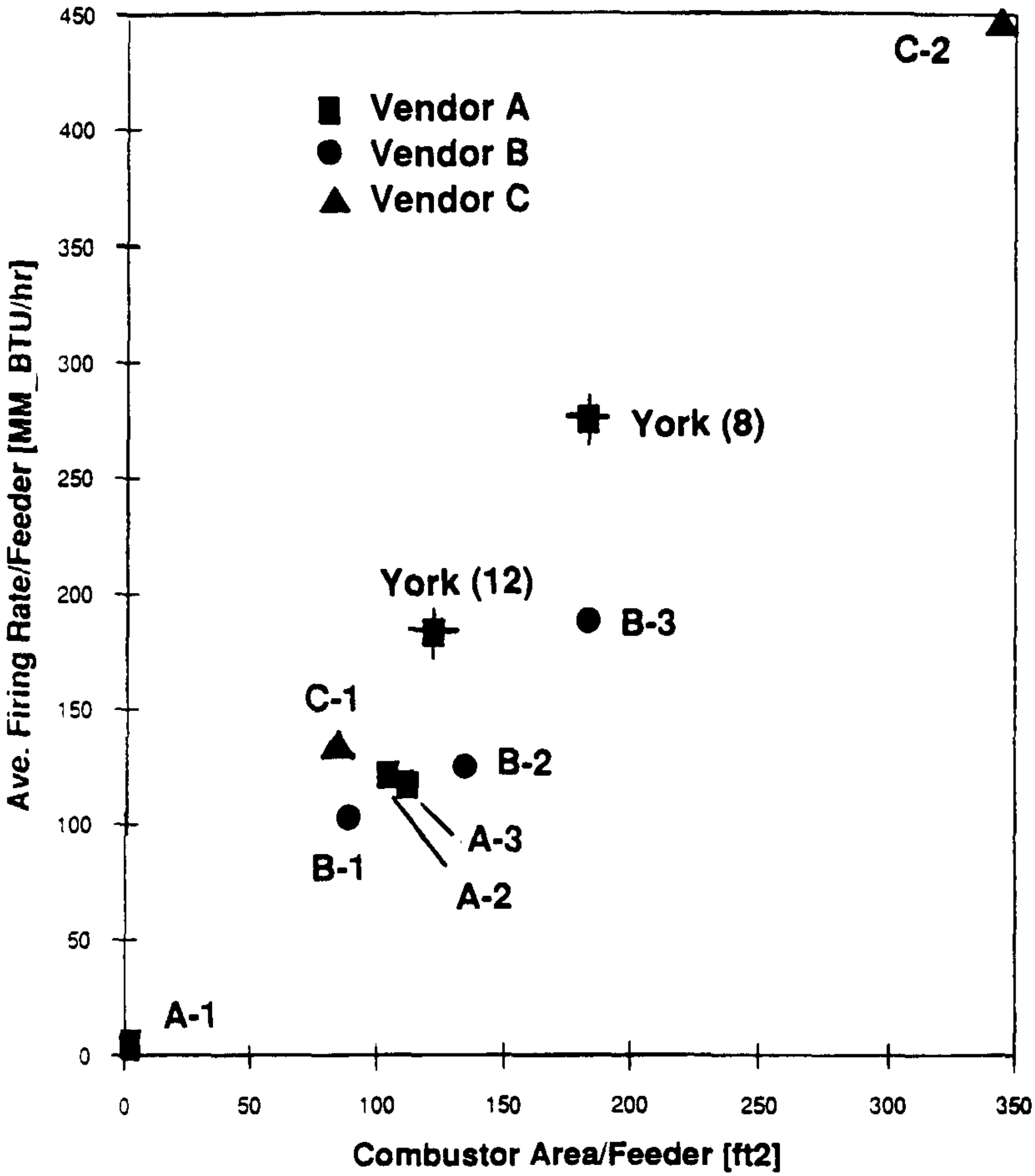



**Figure 15(a). Comparison of Firing Distribution Based on Combustor Area.**

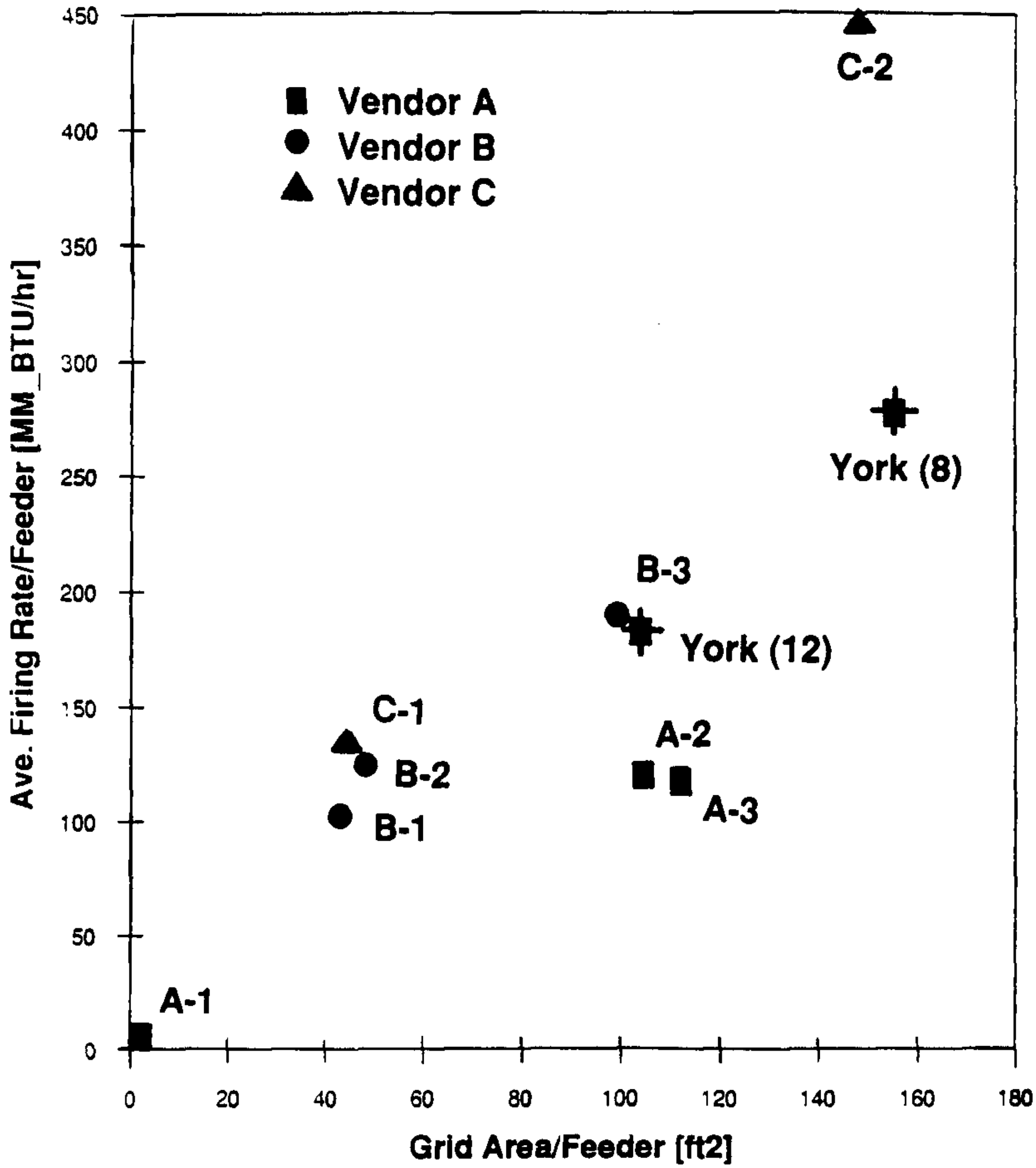



**Figure 15(b). Comparision of Firing Distribution Based on Grid Area.**

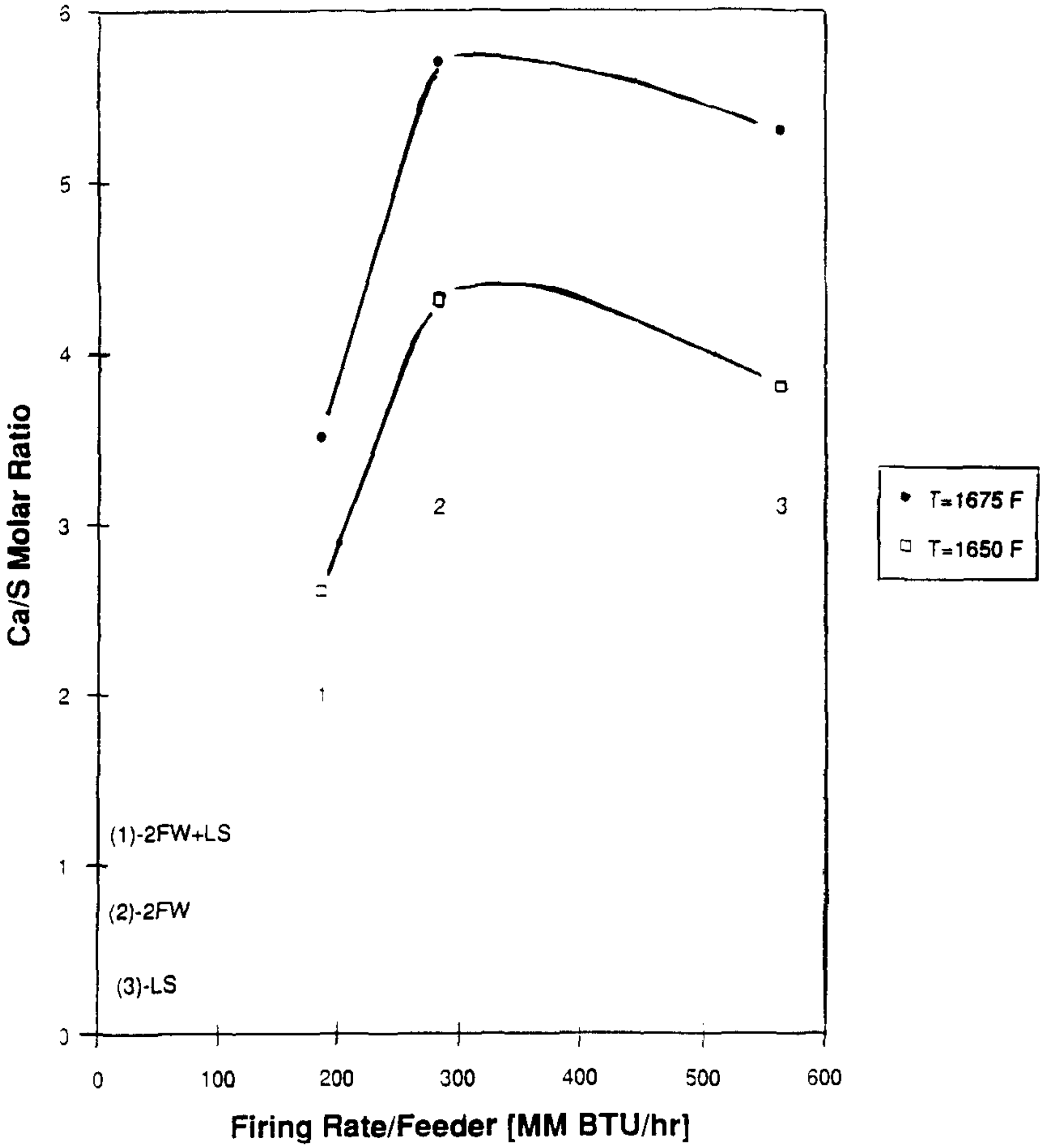



**Figure 16. Effect of Fuel Distribution on Limestone Utilization in Unit B-3.**

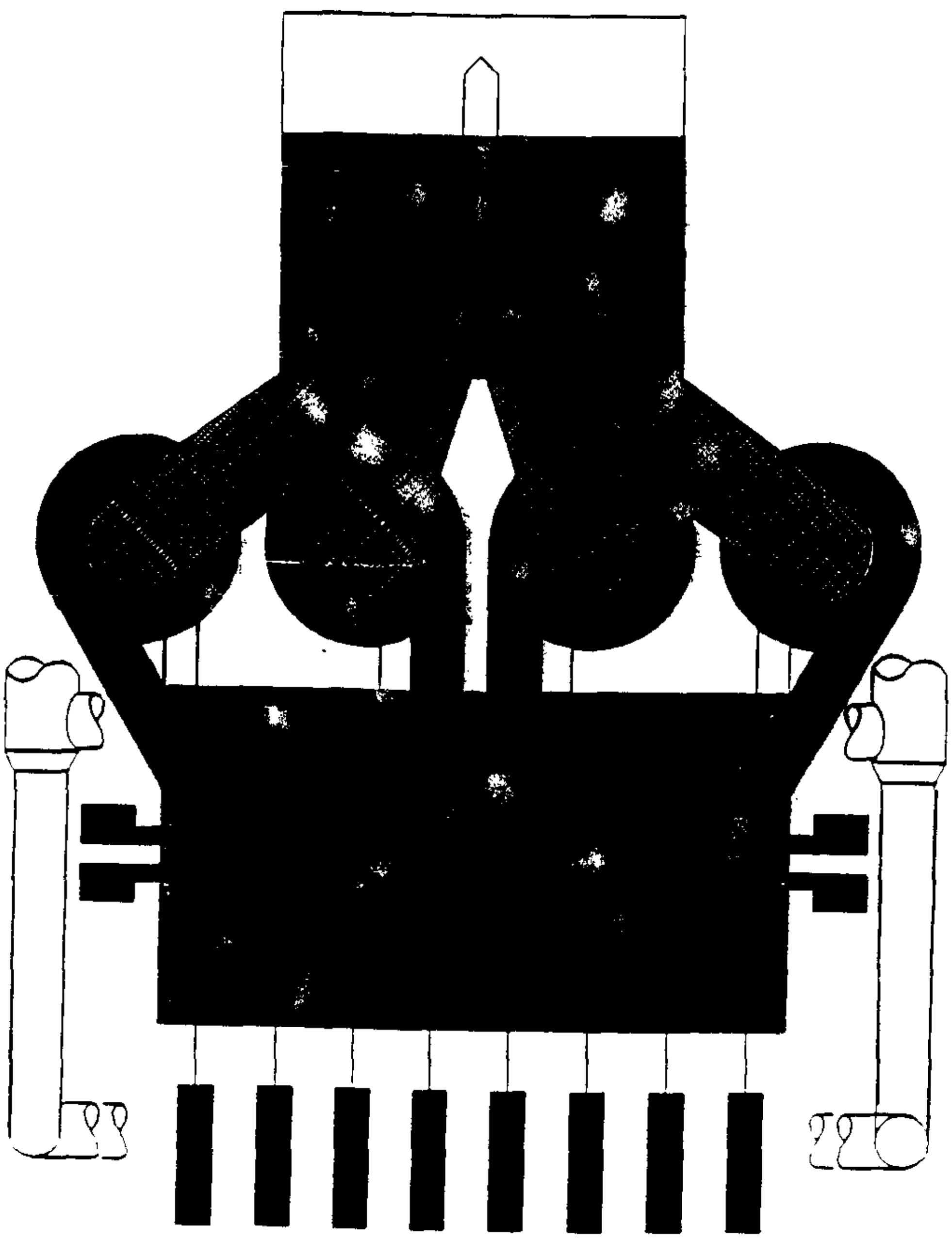


Figure 17. Cyclone Arrangement

# COAL GASIFICATION - AN ENVIRONMENTALLY ACCEPTABLE COAL-BURNING TECHNOLOGY FOR ELECTRIC POWER GENERATION

Paul R. Thibeault
Lawrence J. Peletz
Herbert E. Andrus, Jr.

## INTRODUCTION

Combustion Engineering Inc. (CE) recently received approval from the federal Department of Energy (DOE) to proceed with the design of a $270 million integrated coal gasification combined cycle (IGCC) repowering project with City Water, Light & Power in Springfield, Illinois (CWL&P).

The project, which will provide the utility with a nominal 65 MW of electricity, will demonstrate a gasification system specifically designed for use by the electric utility industry -one that is similar in many ways to today's pulverized coal-fired steam generators.

The use of standard boiler practices means the plant will be operated like a standard, pulverized coal power plant. Upon completion of the CWL&P project, CE intends to offer the same IGCC process on a commercial scale. The CWL&P project will demonstrate all major IGCC subsystems, including:

- Coal feeding system
- CE's advanced air-blown coal gasification
- Advanced method of coal gas cleanup
- A conventional combustion turbine appropriately adapted to utilize low-Btu coal gas as fuel.
- The integration of the combustion turbine with the existing plant system to provide a complete, combined cycle operation.

## Market Forces

In the United States, coal is currently used to produce approximately 55 percent of the country's electricity. With amendments to the Clean Air Act now firmly in place, coal-burning electric utilities throughout the country must comply with increasingly stringent environmental regulations.

Coal gasification is a process in which coal is used to produce a clean fuel gas which, in turn, is burned to produce power. Because most pollutants (such as sulfur) are removed prior to the combustion process, the fuel gas can be burned in an environmentally acceptable manner.
As a result, "clean coal technologies" like coal gasification are now being proposed as viable alternatives to traditional coal burning power plants.

The federal Department of Energy (DOE) forecasts that coal will maintain its dominance in power generation and that after 2005 significantly more than 50 percent of the growth in electricity generation will come from coal-fired plants.

For IGCC, the potential repowering market is large and includes many existing utility boilers currently fueled by coal, oil or natural gas. According to the DOE, 44 percent of the U.S. coal-fired capacity will be 30 years old or older by the year 2000. In addition to a greater, more cost-effective reduction of $SO_2$ and $NO_x$ emissions, net plant heat rate can also be improved.

## Demonstration Project

The CWL&P project will demonstrate IGCC by repowering one of the utility's existing Springfield plants. The project duration is scheduled to last 126 months, including a five-year demonstration period.

The project will repower CWL&P's Lakeside station and provide an IGCC power plant with low environmental emissions and high net plant efficiency. It will increase the original plant output to provide a total IGCC capacity of a nominal 60 MWe. Nearly half of the project is being funded by the DOE, under the Clean Coal II Program, while CWL&P, the State of Illinois, and CE will fund the rest.

The most important aspect of the CE system is that it does not require the oxygen plant common to many of today's coal gasification systems. Instead, it will use CE's air-blown gasification technology, which is similar in many ways to the technology most common to electric utilities throughout the world -pulverized coal (PC) fired boilers.

## Gasification Development

In an integrated electric power plant application, the gasification system is part of a two step coal combustion process. In the first, or gasification step, the coal is partially reacted with a deficiency of oxygen to produce a fuel gas which is then cleaned before it is burned in a boiler and/or gas turbine.

Functionally integrating the gasification plant with the combined cycle plant at the CWL&P facility will require the interchange of steam and boiler feed water between the plants and the sharing and linked operation of many plant utilities and auxiliary systems.

The CE gasification process will provide more than 95 percent energy conversion efficiency in the gasification portion of the plant, from raw coal input to energy output, in the form of usable steam and clean fuel gas. The system is applicable to all coals, including high-sulfur, caking coals.

## Air-Blown Gasification

While there are essentially two types of coal gasification -oxygen-blown and air-blown - most current gasification development has focused on the oxygen-blown technology. Oxygen-blown gasifiers were developed by the chemical/petroleum industry to produce a medium-Btu synthesis gas for further processing into alternative fuels (e.g. synthetic natural gas and methanol).

CE anticipates that its air-blown technology demonstrated at CWL&P will be simpler and less expensive than an oxygen-blown plant, because the system (1) eliminates the need for an oxygen plant and (2) uses a hot gas cleanup technology instead of the traditional low temperature gas cleaning equipment.

The result will be a lower cost of energy, since the parasitic power required to operate the oxygen plant and gas cleaning equipment is reduced, thereby reducing the overall heat rate and increasing the plant's net efficiency.

In addition, CE's system will produce a low Btu gas that burns at lower temperatures, which reduces the formation of nitrogen oxides (NOx) in the gas turbine and improves the system's overall environmental impact. According to manufacturers, this low-Btu gas can be burned in all major gas turbines for integrated gasification combined cycle (IGCC) applications.

## ABB CE's Integrated Gasification Process

In the early 1970's CE evaluated numerous gasification processes and determined that a two-stage, entrained-flow, air-blown, slagging bottom gasification process would be best for utility power generation applications. In 1974, CE began a study which ultimately led to the development of an atmospheric pressure version of the entrained-flow coal gasification system.

The process was developed in a Process Development Unit (PDU) located in Windsor, Connecticut. The unit gasified Pittsburg seam coal at a nominal firing rate of 120 tons per day (TPD). The project met its planned objective to produce clean, low-Btu gas from coal and provided the design information for scale-up to commercial-size plants.

The CE process at CWL&P will use an entrained flow, two stage, slagging bottom gasifier. Figure 1 shows a schematic of the gasifier concept and Figure 2 shows the main components of gasifier island. Some of the coal and all of the unburned carbon and ash (called char) is fed to the combustor section while the remaining coal is fed to the reductor section of the gasifier.

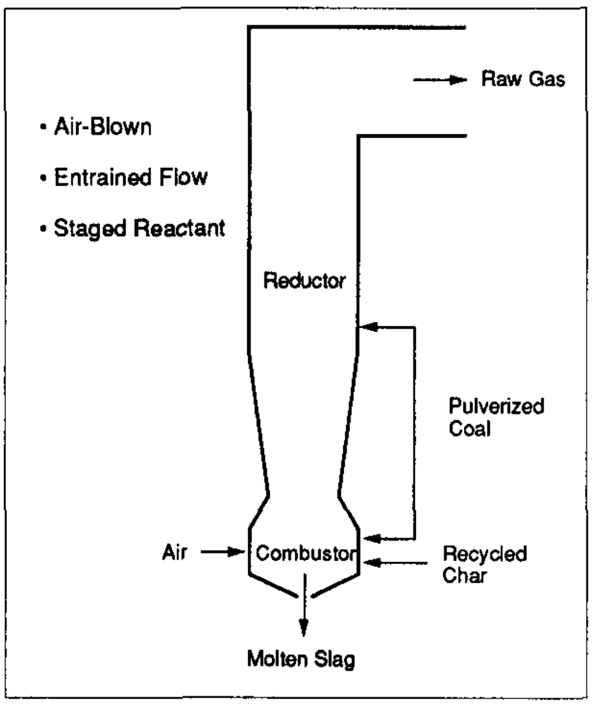



**Figure 1. CE Gasifier**

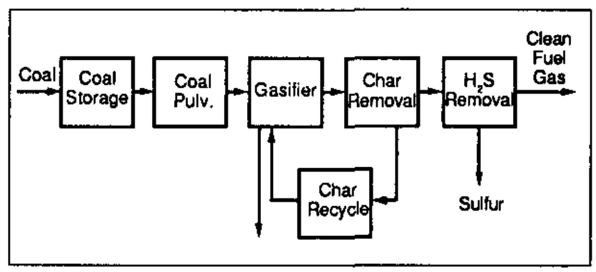



**Figure 2. Gasifier Island**

The coal and char in the combustor mix with air and the fuel-rich mixture is burned, creating the high temperature necessary to gasify the coal and to melt the mineral matter in the coal. The slag flows through a slag tap at the bottom of the combustor into a water-filled slag tank where it is quenched and transformed into an inert, vitreous, granular material. This slag is non-leaching, making it easy to dispose of in an environmentally acceptable manner.

The hot gas leaving the combustor enters the second stage called the reductor. In the reductor, char gasification occurs along the length of the reductor zone until the temperature falls to a point where the gasification kinetics become too slow. Once the gas temperature reaches this level, essentially no further gasification takes place and the gases subsequently are cooled with convective surface to a temperature low enough to enter the cleanup system.

Thus, nearly all of the liberated energy from the coal that does not go into producing fuel gas is collected and recovered with steam generating surface either in the walls of the vessel or by conventional boiler convective surfaces in the backpass of the gasifier. This boiler style design provides for recovery of coal energy as either fuel gas or steam (for use in a steam turbine to generate electricity).

The char is carried out of the gasifier with the product gas stream. The char is collected and re-cycled back to the gasifier, where it is completely consumed. Thus, there is no net production of char which results in negligible carbon loss.

The product gas then enters a desulfurization system where it is cleaned of any sulfur compounds present in the fuel gas. The clean fuel gas is now available for use in the gas turbine combustor for a combined cycle application.

Coal Preparation and Feed System

The CE coal preparation and feed system is designed to pulverize crushed coal, dry and heat it, feed it through a pressure barrier, and meter it into the gasifier. The system utilizes lock hoppers to overcome the pressure barrier and a pressurized feed bin with metering devices to feed pulverized coal into the gasifier's fuel lines.

Transport gas will be used to convey the coal to the gasifier. The system extends from the inlet of the raw coal feeder to the inlets of the gasifier (See Figure 3 for the system schematic).
Crushed coal will be taken from the raw coal bin and metered into a pulverizer by the raw coal feeder. The pulverized coal will be dried and conveyed to a separation system positioned above the feed system to promote a gravity flow into the various feed system vessels.

The coal continues to flow by gravity to a receiving bin, and then into one of two lock hoppers. Each lock hopper will be capable of pressurizing its contents from atmospheric pressure to the gasifier's operating pressure and discharging the contents into a feed bin which remains at this pressure.

The lock hoppers will operate in sequence. As one fills with coal, the other will dump coal into the feed bin. The feed bin, which will operate at a pressure higher than the gasifier's, will provide an inventory of coal which can be metered into the gasifier.

An alternate coal feeding system, which is being considered, involves the use of a kinetic extruder, developed by Lockheed. This device will feed coal through the pressure barrier and into the feed bin.

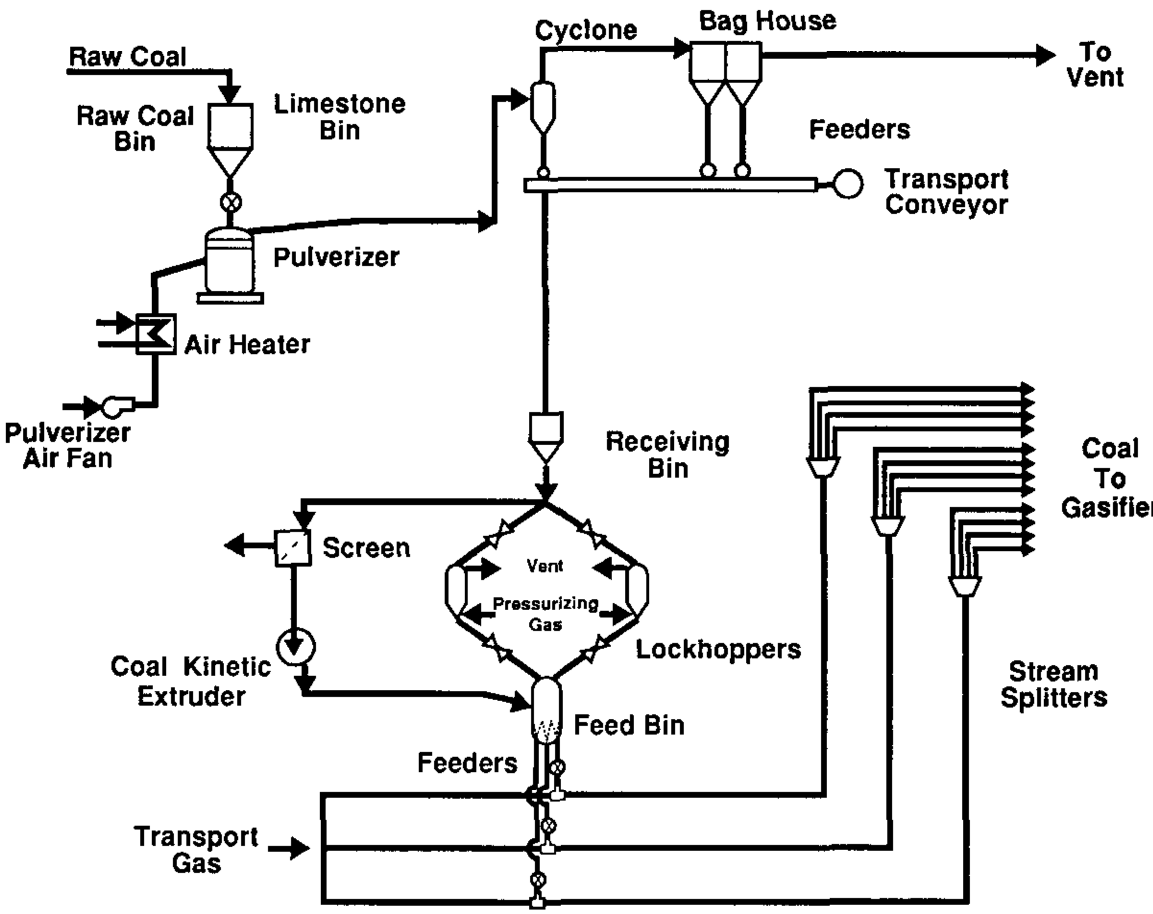



**Figure 3. Coal Preparation and Feed System**

## Char Removal System

The char removal system will improve the IGCC's efficiency by removing the char in the product gas stream and returning it to the gasifier. Two particulate removal devices will operate in series. The first is a cyclone which is followed by a barrier filter. The cyclone removes the larger size particles, while the barrier filter removes the rest. The cyclone can be either a single- or two-stage series, while the barrier filter may be of any of the new technologies available.

The leading candidate for the barrier filter is a design similar to a conventional baghouse, but with an advanced high-temperature material for the bags. With the baghouse concept, the particles are collected on the outside surface of the bags. To remove the particles, a pulse-jet cleaning system is employed. This pulse jet system is integral with the baghouse. The cleaning cycle is established by monitoring the pressure differential across the collector. When a target pressure differential is reached either all or some of the collecting elements are cleaned. The particles collected by the cyclone and baghouse are then discharged into a char receiving bin.

## Char Recycle System

The char collected from the product gas stream is re-pressurized and fed back into the gasifier. Transport gas is used to convey the char to the gasifier (Figure 4).

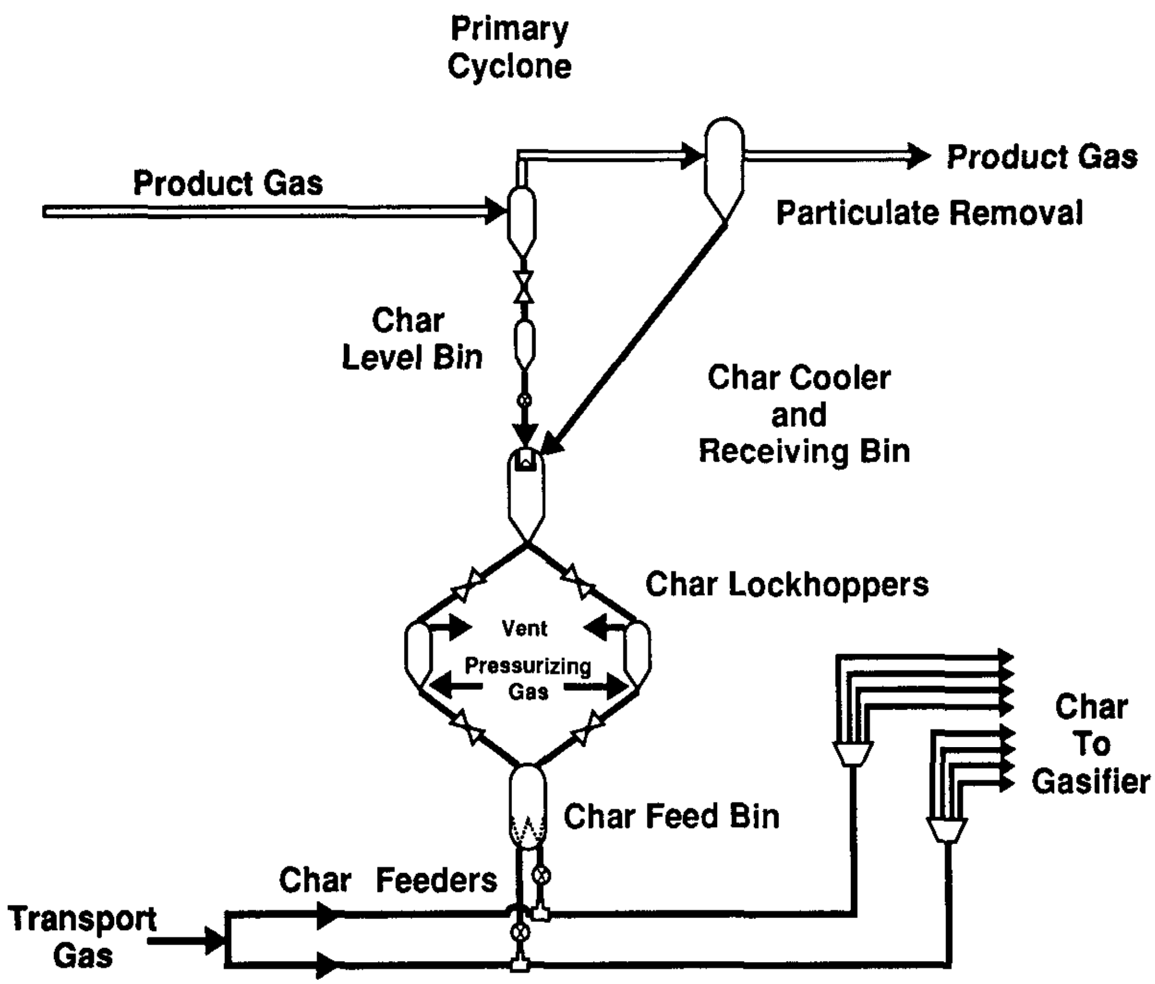



**Figure 4. Char Recycle System**

The reclaimed char is deposited into a receiving bin and flows by gravity into one of two char lock hoppers, where it is pressurized and gravity-fed into a char feed bin. These lock hoppers also operate in sequence, with one filling while the other discharges into a feed bin. From the feed bin, char is metered, mixed with transport gas, and conveyed through char feed lines to the gasifier.

## Hot Gas Cleanup

The CE gasification process is compatible with both conventional hot gas cleanup systems and those currently under development. The CWL&P project will include the design and demonstration of a system developed by General Electric's Environmental Services Inc. (see Figure 5).

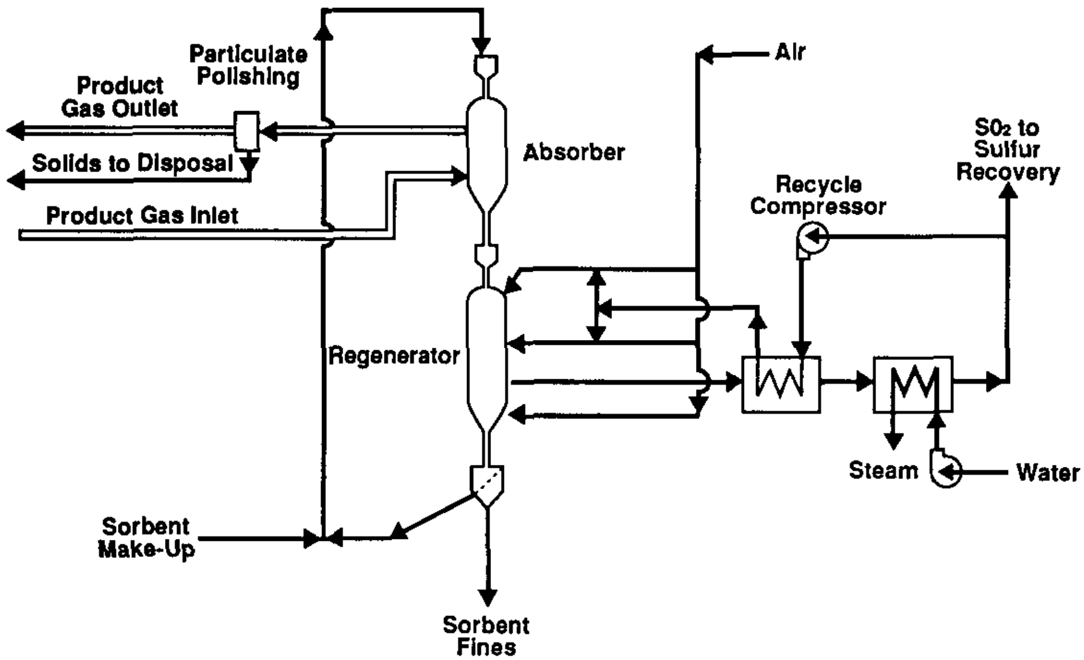



**Figure 5. Sulfur Removal System**

The removal system will feature a newly developed moving-bed zinc ferrite sulfur removal system downstream of the gasifier. CE intends to use the GE moving bed, zinc titanate moving bed, hot gas desulfurization and particulate removal system currently being piloted by GE. The process data from the pilot test will be used to design a full-scale system at CWL&P.

The CWL&P hot gas cleanup system will use the full fuel gas flow at 20 atmospheres psig with an outlet temperature that will range from 850 to 1150 degrees Fahrenheit.

Fuel gas derived from coal contains sulfur, mainly in the form of H2S with some COS. Mixed metal oxide components can react with the gaseous sulfur species forming regenerable metal sulfides under reducing conditions in the temperature range of 800 to 1200 degrees Fahrenheit. GE's patented moving bed process includes the regeneration of a sorbent material.

At CWL&P, the scaled up version of the GE system is expected to achieve:

- Greater than 99 percent overall sulfur removal at full gasifier operating conditions.
- A reduction of concentrated particulates to levels acceptable for gas turbine and NSPS requirements.
- Minimized net consumption of sorbent.

- Production of an $SO_2$-rich tail gas suitable for conversion to sulfuric acid, elemental sulfur or disposable waste.

Burning Low-Btu Gas in Today's Gas Turbines

CE's air blown process is compatible with both current generation gas turbines, as well as those presently under development.

At the CWL&P plant, the gasifier's low Btu gas (LBG) will be burned in a standard General Electric Frame 6 gas turbine, modified for low-Btu gas. The turbine will also fire natural gas during start-up. Projected performance for the plant is shown in Table 1.

**Table 1**
**Project Performance Summary**

| | | ISO WSSF | 95°F WSF |
|---|---|---|---|
| Coal to Gasifier (TPD) | 580 | 650 | 586 |
| Combustion Turbine Power (Mwe) | 33 | 38 | 33 |
| Steam Turbine Power (MWe) | 32 | 33 | 36 |
| In-Plant Use (Mwe) | 5 | 9 | 9 |
| Net Power (Mwe) | 60 | 62 | 60 |
| Heat Rate (Btu/Kw) | 8800 | 9100 | 9500 |

In recent years, the perception of supply limitations and increasing costs of conventional clean fuels like oil and gas has renewed interest in coal and other solid fuels in combined cycle operations. Recent advances in gas turbine design are establishing new levels of combined cycle plant efficiencies and providing the potential for a significant shift to gas turbine solid fuel power plant technologies.

These new efficiencies can economically deliver superior environmental performance. As a result, the combined cycle process has become so efficient that it can incorporate coal gasification and still deliver superior cycle efficiency.

New gas turbine combined cycles firing natural gas can operate on clean fuel at 54 percent (LHV) net thermal efficiency. Given this level of performance, a 7900 Btu/kWhr (HHV) heat rate can be demonstrated with IGCC technology today. The CE performance projections in Table 2 incorporate current generation combined cycle technology.

Table 2
Coal Gasification Combined Cycle
Potential Performance

| | | |
|---|---|---|
| Steam Turbine | (MW) | 100 |
| Gas Turbine | (MW) | 150 |
| Plant Auxiliary Power | (MW) | 15 |
| Total Net Power | (MW) | 235 |
| Net Plant Heat Rate | (BTU/KW-HR) | <8000 |
| $SO_2$ Emissions | (LB/MMBTU) | <0.1 |
| $NO_x$ Emissions | (LB/MMBTU) | <0.1 |
| Particulate Emissions | (LB/MMBTU) | <0.03 |

The IGCC process at CWL&P will separate the ash as an inert slag, convert virtually all the carbon in the gasifier, and remove 99 percent of the sulfur. The resultant coal gas is an excellent fuel for standard production gas turbines. Most conventional turbines require only burner modification for use in an IGCC system.

For the CE air blown system, air extraction is provided to allow the fuel to pass through the standard turbine without raising the pressure above the compressor surge margin. The air extracted is used to pressurize the gasifier, which also maintains balanced turbine flows.

Gasification Process Advantages

CE has considerable experience in building reliable entrained flow pulverized coal boilers. As previously noted, the use of standard boiler practices means the plant will be operated like a standard coal fired power plant - an important consideration for electric utilities. The design provides for fast load following similar to a pulverized coal boiler. This allows an easier start-up from cold and hot status. The process provides many other advantages for high-efficiency electric power production, including:

- A gasifier that is well-suited for scale-up to the sizes required to achieve economy of scale in large power plants.
- All types of coal can be processed without special pre-treatment.
- Virtually all char produced is consumed. There is no net char production and carbon loss is negligible.

- Ash disposal is minimized by fusing the ash into a molten slag in the gasifier. After water quenching, the coal ash is in its most acceptable form for disposal.
- CE's gasifier does not produce unwanted tars and oils in the product gas.
- The use of air in the gasifier eliminates the complexities and high cost of an oxygen separation plant and significantly lowers the plant's capital and operating costs.
- Extremely low SOx and NOx emissions.

Integrating CE's Design Into A Combined Cycle Operation

The integrated gasification combined cycle system at CWL&P will have two major equipment blocks (Figures 6 and 7):

- The air-blown gasifier, including coal preparation and feed, gasification and gas cleanup.
- The combined cycle plant, which includes the gas turbine which burns the clean fuel gas to produce electricity; and exhaust heat recovery boilers, which power traditional high efficiency steam turbines that generate additional electricity.

Integrated gasification combined cycle is considered to be one of the cleanest, most efficient alternatives for producing electricity from coal. Compared to a conventional coal-fired power plant equipped with scrubbers, an IGCC power plant will:

- Reduce emissions associated with the creation of acid rain to levels far below federal clean air standards, exceeding the performance of conventional coal combustion and cleanup (scrubber) technologies.
- Minimize $CO_2$ emissions by maximizing plant efficiency.
- Minimize the solid waste volume normally associated with scrubber technology.

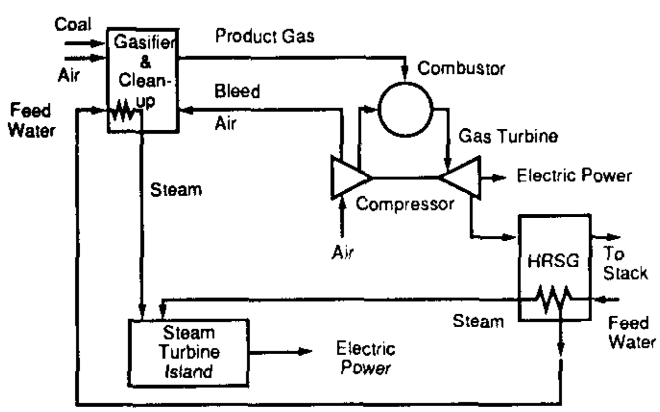



**Figure 6. Simplified IGCC**

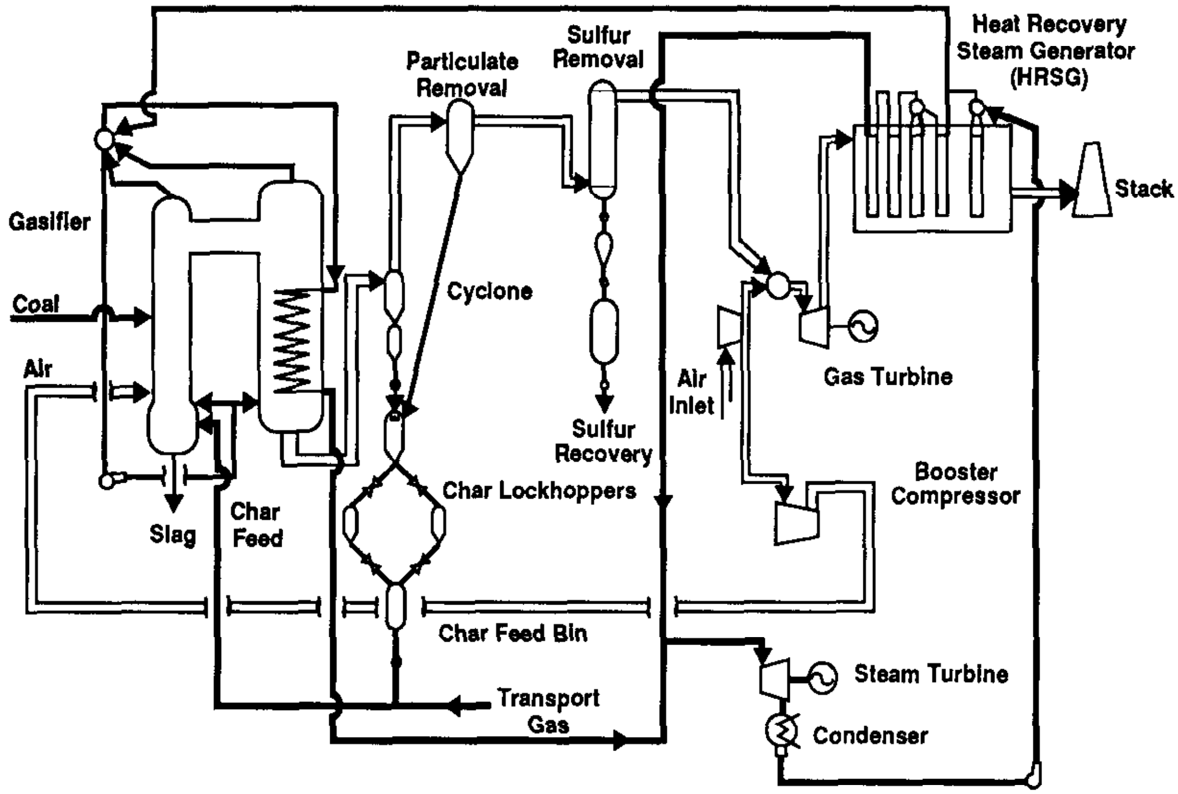
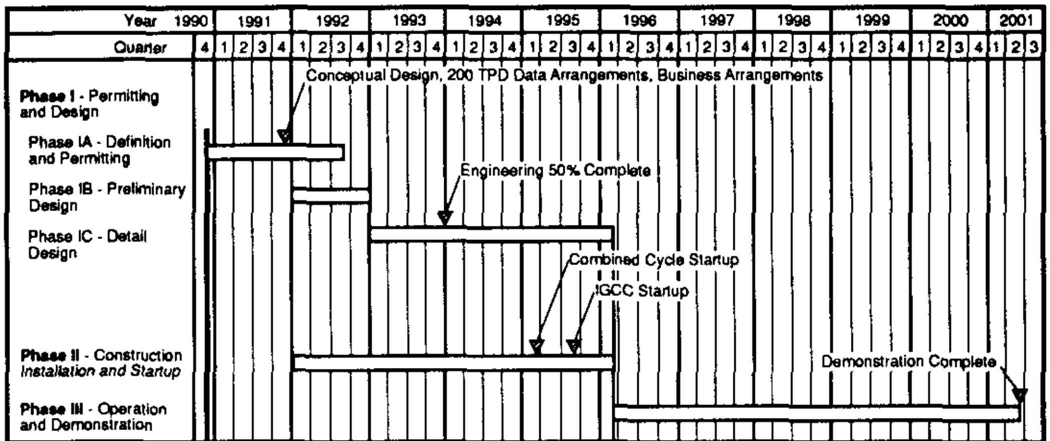



**Figure 7. CE IGCC Flow Diagram**

In addition, IGCC is expected to provide electricity at a cost that is competitive with pulverized coal power plants that meet federal clean air standards.

As each major equipment section is completed, it will be brought on line to produce power. To facilitate startup of the IGCC, the combined cycle equipment will be installed, checked out, and brought into commercial service first. The complete operation of this equipment will make the plant a combined cycle fired on natural gas. All the equipment will be checked out and operated prior to the start-up of the gasification plant.

The other major block of equipment will be the fuel gas island, including the gasifier and hot gas cleanup equipment sections. When this equipment is put into operation, the plant will be a full integrated coal gasification combined cycle plant. The overall project timetable is shown in Figure 8.




| BUDGET ($MM) | Period #1 | Period #2 | Period #3 | Period #4 | Period #5 | Budget Totals |
|---|---|---|---|---|---|---|
| Phase I | 5.8 | 11.0 | 22.3 | 17.6 | - | 56.7 |
| Phase II | - | - | 6.0 | 88.3 | - | 94.3 |
| Phase III | - | - | - | - | 119.7 | 119.7 |
| Totals | 5.8 | 11.0 | 28.3 | 105.9 | 119.7 | 270.7 |

Project Funding Plan (Dollars in Millions)

**Figure 8. Combustion Engineering IGCC Repowering Project - Schedule and Budget**

## CONCLUSION

Despite energy conservation efforts throughout the country, future electricity use is expected to grow in all consumption sectors - residential, commercial and industrial. In addition, coal is expected to remain the dominant source of fuel in the United States. As a result, IGCC is expected to become a new technology of choice for the power industry because of its ability to:

- Reduce emissions from the coal based power generation currently associated with acid rain.
- Produce clean, efficient energy while minimizing solid waste disposal requirements.
- Operate at greater thermal efficiencies than scrubber-equipped, coal-fired plants, *reducing $CO_2$ emissions and cutting fuel costs.*
- Provide an efficient technology that can be applied to both new plants, or repowering existing facilities.
- Provide a clean, efficient way to use coal, the nation's most important domestic energy source.
- CE's IGCC system is aimed specifically at meeting the needs of the electric power industry.

# TOMS CREEK IGCC DEMONSTRATION PROJECT

## ABSTRACT

The Toms Creek Integrated Gasification Combined Cycle (IGCC) Demonstration Project was selected by DOE in September 1991 to participate in Round Four of the Clean Coal Technology Demonstration Program. The project will demonstrate a simplified IGCC process consisting of an air-blown, fluidized-bed gasifier (Tampella U-Gas), a gas cooler/steam generator, and a hot gas cleanup system in combination with a gas turbine modified for use with a low-Btu content fuel and a conventional steam bottoming cycle. The demonstration plant will be located at the Toms Creek coal mine near Coeburn, Wise County, Virginia. Participants in the project are Tampella Power Corporation and Coastal Power Production Company. The plant will use 430 tons per day of locally mined bituminous coal to produce 55 MW of power from the gasification section of the project. A modern pulverized coal fired unit will be located adjacent to the Demonstration Project producing an additional 150 MW. A total 190 MW of power will be delivered to the electric grid at the completion of the project. In addition, 50,000 pounds per hour of steam will be exported to be used in the nearby coal preparation plant. Dolomite is used for in-bed gasifier sulfur capture and downstream cleanup is accomplished in a fluidized-bed of regenerative zinc titanate. Particulate clean-up, before the gas turbine, will be performed by high temperature candle filters (1,020°F). The demonstration plant heat rate is estimated to be 8,700 Btu/kWh. The design of the project goes through mid 1995, with site construction activities commencing late in 1995 and leading to commissioning and start-up by the end of 1997. This is followed by a three year demonstration period.

## INTRODUCTION

The Coastal Corporation is in the energy business and the Coastal Power Production Company (Coastal Power) is specifically in the power production business. As a power producer, Coastal Power is interested in more efficient energy production using fuels such as coal while simultaneously reducing emissions. An IGCC power plant would accomplish both these goals. Tampella Power, Inc. (Tampella Power) is developing a simplified IGCC process applying the

# TOMS CREEK IGCC DEMONSTRATION PROJECT

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Paper presented at First Annual Clean Coal Technology Conference
**in Cleveland, Ohio, on September 22-24, 1992.**

U-Gas gasification technology developed by the Institute of Gas Technology (IGT) and an advanced hot gas clean-up system. An extensive research and development program is underway at Tampella Power on major aspects of the IGCC process. A pressurized gasification pilot plant of 10 MW thermal input was commissioned in October 1991 in Tampere, Finland, and an ambitious test program has been going on since. Over 550 hours of gasification test were logged up to the end of May '92.

Tampella Power's IGCC concept incorporates the pressurized fluidized-bed gasification of different solid fossil fuels, applying air-blown gasification and hot gas clean-up integrated into a power (and heat) generating combined cycle. This type of IGCC-system has the advantages of higher power generation efficiency, high power to heat ratio for cogeneration, excellent environmental performance, simple plant configuration and modularity. The investment cost of the simplified IGCC is moderate while it enjoys the availability of abundant solid fuels.

The Demonstration Project site is at the existing Tom's Creek coal mine near Coeburn, in southwest Virginia. The plant location is close to the existing coal preparation plant. The site, coal reserves and the fuel preparation plant are owned by a subsidiary of the Coastal Corporation. The IGCC section of the power plant consists of a 430 ton/day U-Gas gasifier complete with hot gas clean-up equipment feeding a gas turbine converted to burn the low-Btu content fuel gas (typically LHV 130 Btu/scf) before exhausting to a heat recovery steam generator.

To meet the economic requirements of the project Coastal Power will build a nominal 150 MW pulverized coal power plant at the same site. The steam turbine will be common to the demonstration project and to the PC boiler to achieve some economics of scale for the project. The IGCC section of the plant will produce 55 MW electric power, and the total nominal output of the plant will be 205 MW.

## PROJECT TEAM STRUCTURE

Tampella Power Corporation and Coastal Power Production Company have formed a general partnership called TAMCO Power Partners for the execution of the demonstration project (See Figure 1.). Tampella Power Corporation of Williamsport, Pennsylvania is a subsidiary of Tampella Power Inc., a major international supplier of chemical recovery boilers, fluidized bed boilers and air pollution control equipment. Tampella Power will provide the coal gasification plant for the project and will commercially develop the demonstrated technology. Coastal Power Production Company of Roanoke, Virginia is a subsidiary of The Coastal Corporation, which is a natural gas, coal, oil and independent power production company with annual revenues in 1991 of over $9.5 billion. Coastal Power has three (3) operating natural gas combined cycle plants in operation with a total output of 330 MW. Coastal Power will design, construct, and operate the power plant. Other Coastal subsidiaries will provide the site, fuel, and ash disposal facilities for the project. The TAMCO General Partnership Agreement provides for the commercial terms between the partners, including site lease, coal supply, coal gas and steam sales, utility services and performance for the gasification system. The partnership is also the interface to the DOE and is the signatory of the Cooperative Agreement.

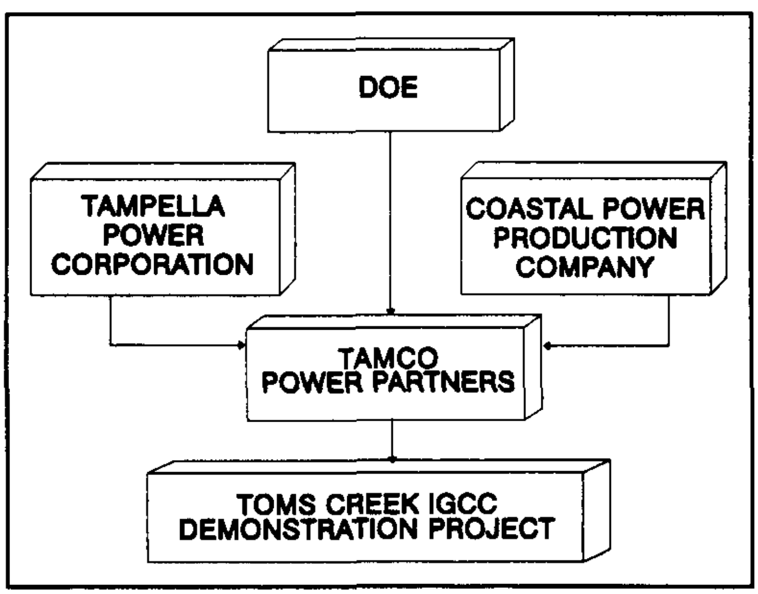


**Figure 1. Toms Creek Project Team**

## THE U-GAS TECHNOLOGY DESCRIPTION

The U-Gas process is a pressurized fluidized bed coal gasification process which produces low to medium Btu content fuel gas from a variety of feedstocks including highly caking, high sulfur, and high ash coals. A simplified schematic diagram of the U-Gas gasifier is shown in Figure 2.

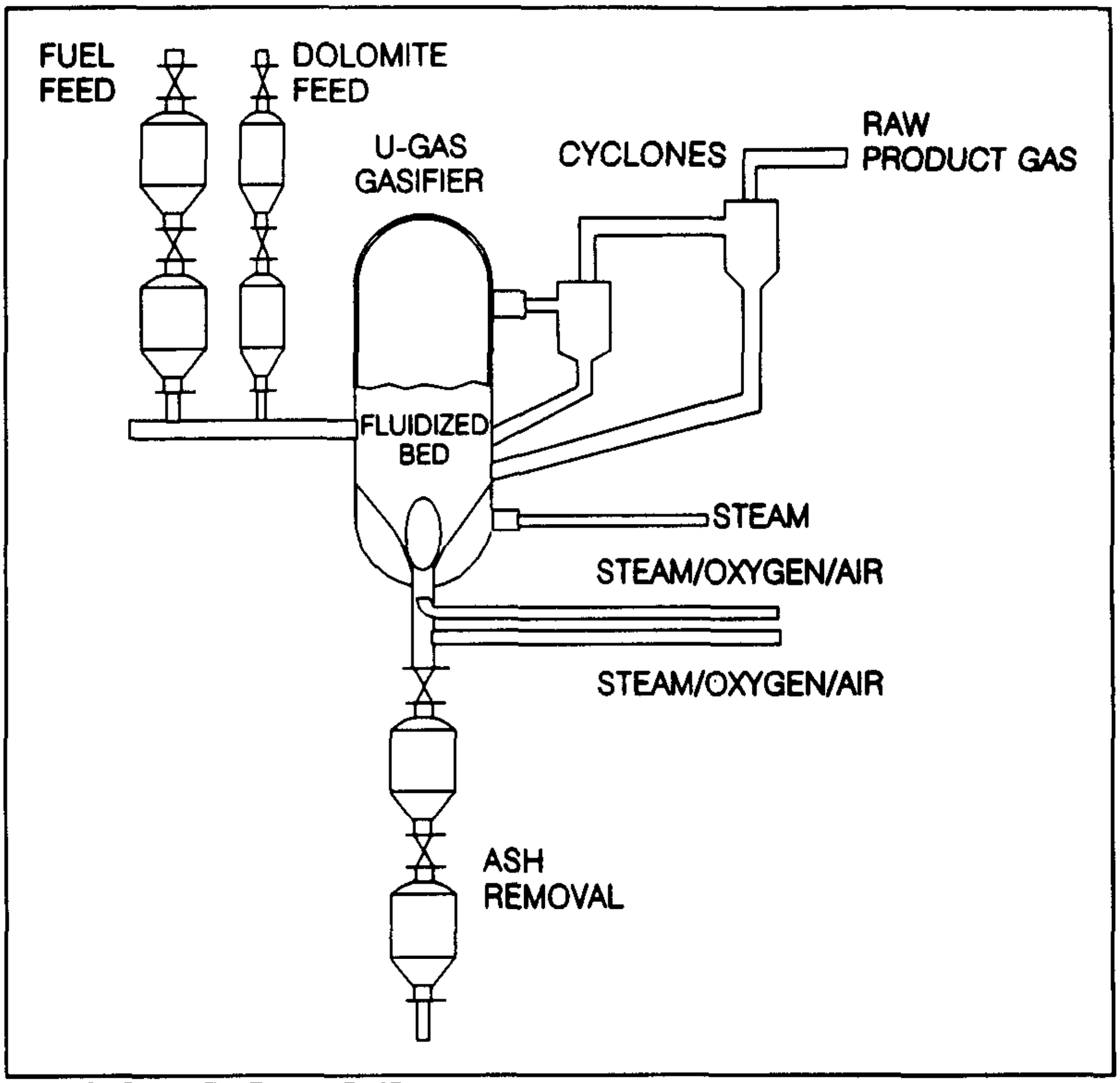


**Figure 2. The U-Gas Process Gasifier**

The Gasifier

The crushed (¼" x 0) coal is first dried to below 5% moisture in a dryer. The coal and dolomite are then fed to the lockhopper system before being fed pneumatically to the gasifier. Within the fluid bed gasifier the coal is cracked, devolatilized and gasified with the fluidizing medium of air and steam. The coal reacts with air and steam at a temperature of 1,650-1840°F. The temperature within the bed depends on the type of coal and is controlled to maintain non-slagging conditions for the ash. Coal is gasified rapidly in the gasifier and produces a gas mixture of carbon monoxide, carbon dioxide, methane, hydrogen, water vapor and about 50% nitrogen, in addition to hydrogen sulfide, ammonia, and other trace impurities. In the reducing environment of the gasifier nearly all of the sulfur present in the coal converts to hydrogen sulfide before it reacts with dolomite.

The fluidizing gas is introduced into the reactor through the gas distributor plate and through the ash discharge device. The U-Gas feature of controlling the oxidizing zone achieves a low level of carbon losses which enables a very high overall carbon conversion of higher than 97%. The fines elutriated from the fluidized bed are separated from the product gas in two stages of external cyclones. The fines from both stages are returned to the fluidized bed. The product gas is virtually free of tars and oils due to the relatively high temperature in the upper stage of the gasifier (1,840°F).

Sulfur removal system

The main sulfur compound in the gasifier gas is hydrogen sulfide. In Tampella Power's IGCC process desulfurization is accomplished in two stages, which results in a total sulfur removal of over 99% (See Figure 3).

The bulk of sulfur is removed in the fluidized bed gasifier by means of dolomite. Hydrogen sulfide reacts with calcium carbonate and/or calcium oxide forming calcium sulfide. This compound is unstable and has to be stabilized. This is accomplished by oxidizing it to calcium sulfate within the gasifier for safe disposal.

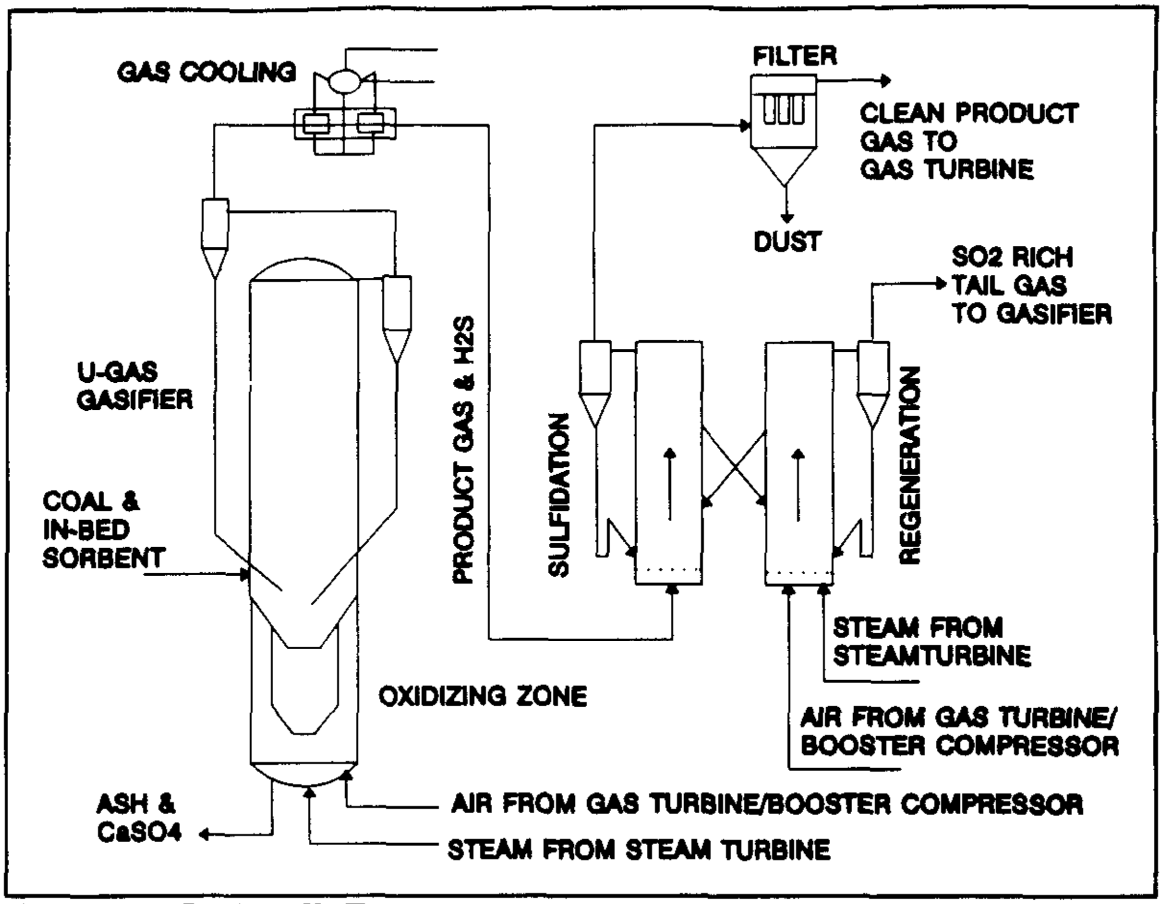


Figure 3. Hot Gas Clean Up Flowsheet

Regenerable Zn/Ti-based sorbents will be used for the post-gasification stage sulfur removal. Tampella Power has developed a two fluidized-bed reactor system for the sulfidation-regeneration cycle. Fuel gas is contacted with Zn/Ti-sorbent in the first reactor, where sulfur is captured by zinc oxide (sulfidation). Sulfided sorbent is regenerated in the second reactor using air for oxidation and steam for temperature control of the highly exothermic reaction (regeneration). The sulfur dioxide-rich regenerator offgas is recycled back to the gasifier to be captured in-situ by dolomite.

Nitrogen Compounds

The fuel nitrogen in the coal forms ammonia and a smaller amount of hydrogen cyanide in the gasifier. Since the gasification temperature is high in the U-Gas process, the ammonia is partly decomposed in the gasifier. To reduce the ammonia/NOx conversion, a staged combustion system is used in the gas turbine, which is under development by several gas turbine manufacturers.

### Alkali Metals

Volatilized alkali metal compounds such as sodium and potassium chlorides and hydroxides are formed in the gasification of coal. The alkali metal compounds in combination with sulfur are harmful to the gas turbine blades, causing hot corrosion and deposition. In Tampella Power's IGCC process, the product gas is cooled to 1,020°F before the gas turbine. At this temperature the alkali vapors will have condensed on the particles and will be removed by the candle filter.

### Particle Removal

The bulk of the particles elutriated from the gasifier is removed from the gas stream in two stages of cyclones. The dust loading of the product gas after the cyclones is typically 0.2 - 0.3 x $10^{-3}$ lb/scf. Rigid ceramic filters will be used for particle control. Silicon carbide filter elements of candle shape have been developed and tested extensively and are considered to be close to a commercial application. The candle filters are cleaned on-line by pulsing with nitrogen or steam.

### Greenhouse Gases

Greenhouse gases of main concern are carbon dioxide, methane and nitrous oxide. In the IGCC-process methane produced during the gasification burns in the combustor of the gas turbine. Nitrous oxide does not form in the reducing atmosphere of the gasifier and its formation is not expected at the high temperatures encountered in the gas turbine combustor. The emission of carbon dioxide cannot be totally avoided. The only way to reduce $CO_2$ emissions is to improve the efficiency of power generation and this is one of the main features of the IGCC technology. The Tom's Creek Plant will have an efficiency of 40% and later plants have an aim of 47%, resulting in an improvement of some 10-15% in terms of lower carbon dioxide emission.

Overview of Process Development

The Toms Creek IGCC Demonstration Project utilizes the U-Gas coal gasification process, which was developed by IGT in a multi-phase program beginning in 1974. The heart of the U-Gas process is an air-blown, pressurized fluidized-bed coal gasifier. The development of this process utilized knowledge from earlier low and medium-Btu content coal-to-fuel-gas projects at IGT that date back to 1950. The U-Gas process feasibility was demonstrated initially using metallurgical coke and char as feed in a low-pressure pilot plant. The pilot plant was subsequently modified to feed coals, and trial tests were made with subbituminous and bituminous coals. Eventually process feasibility was proved using high-sulfur content, caking bituminous coal as feed, and data were developed for scale-up and design of a commercial plant. Necessary environmental data were also collected and the reactor dynamic response was investigated. This pilot plant had an operating pressure limitation of 50 psig. Due to interest in high-pressure operation for several applications, a high-pressure gasifier was built as a process development unit in 1984. Significant gasification data were obtained in this plant for gasification of subbituminous coal and lignite up to 450 psig. Data were also gathered in this unit under steam-air gasification of a bituminous coal with in-situ desulfurization. In support of several demonstration plant designs, several tests were also conducted in the low-pressure pilot plant with different design feedstocks.

Thus, the pilot plant has been successfully operated on a variety of coals including highly caking, high ash, and high sulfur coals. The process has demonstrated its capability to gasify and produce ash agglomerates from raw coal. The operation of the pilot plant has firmly established process feasibility; safe, repeatable, and reliable operability; and has provided a strong data base for the design of larger plants such as the Toms Creek IGCC Demonstration Project. Successful demonstration of this project will help move the process into the commercial marketplace.

The Toms Creek IGCC Project also utilizes a hot gas cleanup system consisting of removal of sulfur-containing gases and particulate from the hot gas. An integrated pilot plant has also been built by Tampella in Finland to test the combination of gasification and hot gas clean-up. This plant will be used to test the coal for the Toms Creek Project to provide design and environmental data.

## TOMS CREEK PROJECT TECHNICAL DESCRIPTION

### Site and Coal

The greenfield project is developed on a site adjacent to an existing coal preparation plant at Toms Creek. The existing coal refuse disposal facilities will be utilized for ash disposal. Coal for the project will be supplied by the Coastal subsidiary who owns the reserves and prepares the coal. The design coal will be a bituminous, low sulfur (1-1.5% S) coal with a heating value of 13,400 Btu/lb (HHV, dry). At least two high sulfur coals will also be tested during the demonstration period. At least one (1) coal will have a free swelling index greater than five (5).

### Process

A schematic plant flow sheet is shown in Figure 4. Crushed and dried coal, 430 tons per day and dolomite are fed through a lock hopper system to the pressurized fluidized-bed gasifier.

The gasification air is supplied by the gas turbine through a booster compressor/heat exchanger system and the gasification steam is extracted from the steam turbine. Two cyclones are used for primary particle removal. After exiting the cyclones the product gas is cooled to 1020°F in a fire tube type evaporating gas cooler, which is connected to the heat recovery steam generator (HRSG). The external sulfur removal system is located after the gas cooler and as a last step the ceramic candle filter unit purifies the product gas to meet gas turbine and environmental requirements. After filtration the product gas of about 130 Btu/SCF LHV is fed into the gas turbine.

The gas turbine is equipped with air extraction for gasification and is complete with an electrical generator to produce 35 MW of electric power and followed by the HRSG. The HRSG supplies high pressure steam to the steam turbine/generator which is also connected with the pulverized coal boiler, which is outside the scope of the demonstration project. The total power produced by the steam turbine is 176 MW and the total net power delivered to the utility grid is 189 MW.

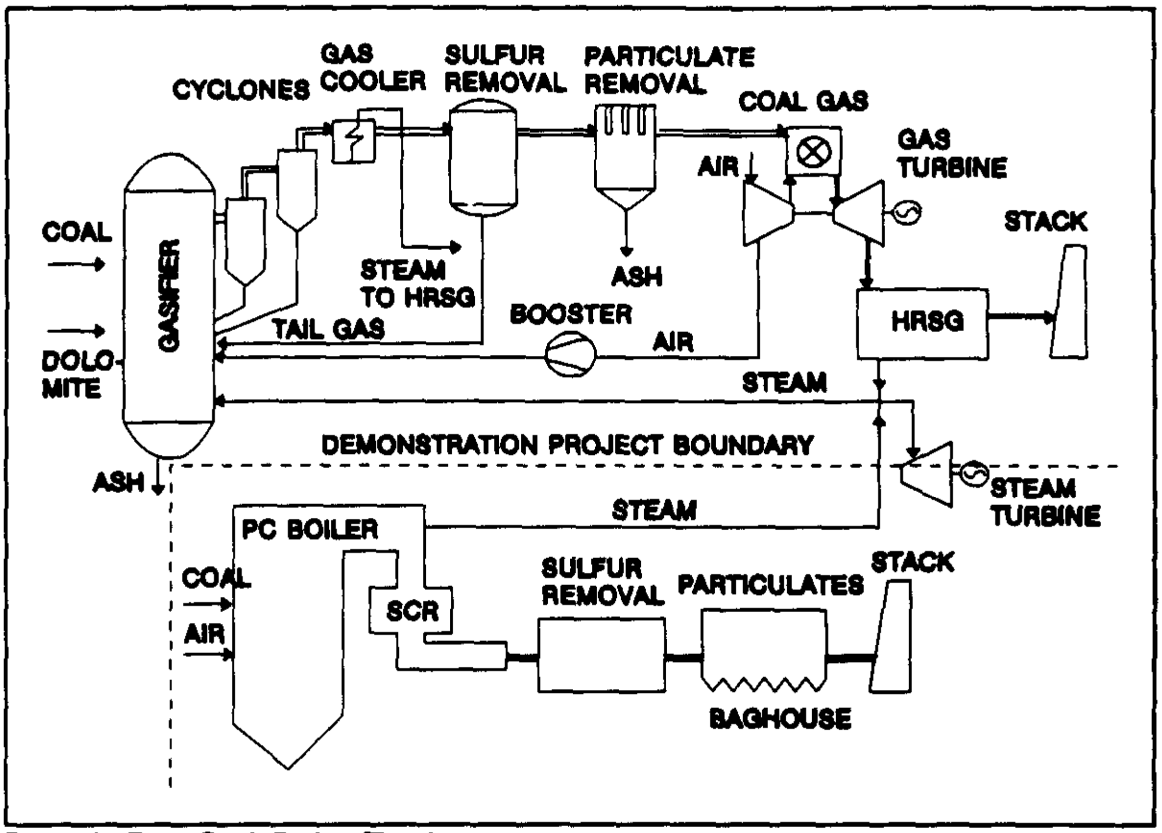


Figure 4. Toms Creek Project Flowsheet

Environmental Performance

The Toms Creek plant does not produce any appreciable process waste water streams. The only solid waste from the plant is a mixture of ash and calcium sulfate which is discharged from the bottom of the gasifier. This is considered a non-hazardous waste and can be utilized in road construction or disposed in a landfill. It is currently anticipated that the glassified product can be placed in the adjacent coal refuse valley, which is part of the coal preparation facility operation. Air emissions from the plant are anticipated to be well below current requirements, with $SO_2$ emission of 0.056 lb/MMBtu, NOx emission of 0.24 lb/MMBtu and particles $PM_{10}$ emission of 0.016 lb/MMBtu.

## PROJECT SCHEDULE

The total duration of the project is eight years. Preliminary design for the process is underway and the detail design will be carried out during 1993-94. Procurement and manufacturing of equipment will be done in 1994-95 and field construction is estimated to begin late in 1995. The demonstration and testing period will take three years beginning in January 1998.

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2. Horvath, A., Mojtahedi, W., Salo, K., Patel, J., and Silvonen, R., "Tampella IGCC Process: Cleaner and More Efficient Power From Solid Fuels." Paper presented at Power-Gen. '91 Conference, Tampa, Florida, 1991.

# SESSION 4: $NO_x$ Control Systems

*Chair: Arthur L. Baldwin, DOE PETC*

**500 MW Wall-Fired Low $NO_x$ Burner Demonstration**, John N. Sorge, Process Engineer, Southern Company Services, Inc. Co-author: Arthur L. Baldwin, Program Coordinator, $NO_x$ Control Technology, U.S. DOE Pittsburgh Energy Technology Center

**180 MW Tangentially-Fired Low $NO_x$ Burner Demonstration**, Robert R. Hardman, Research Engineer, Southern Company Services, Inc. Co-author: Gerard G. Elia, U.S. DOE Pittsburgh Energy Technology Center

**Demonstration of Selective Catalytic Reduction (SCR) Technology for the Control of Nitrogen Oxide ($NO_x$) Emissions from High-Sulfur, Coal-Fired Boilers,** J. Douglas Maxwell, SCR Project Manager and Principal Research Engineer, Southern Company Services, Inc. Co-author: Arthur L. Baldwin, Program Coordinator, $NO_x$ Control Technology, U.S. DOE Pittsburgh Energy Technology Center

# 500 MW WALL-FIRED LOW NOx BURNER DEMONSTRATION

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## ABSTRACT

This paper discusses the technical progress of a U. S. Department of Energy Innovative Clean Coal Technology project demonstrating advanced wall-fired combustion techniques for the reduction of nitrogen oxide (NOx) emissions from coal-fired boilers. The primary objective of the demonstration is to determine the performance of two low NOx combustion technologies applied in a stepwise fashion to a 500 MW boiler. A target of achieving 50 percent NOx reductions has been established for the project. The main focus of this paper is the presentation of the low NOx burner (LNB) short- and long-term tests results.

## TABLE OF ABBREVIATIONS

| | |
|---|---|
| AOFA | Advanced Overfire Air |
| ASME | American Society of Mechanical Engineers |
| C | carbon |
| CFSF | Controlled Flow/Split Flame |
| Cl | chlorine |
| CO | carbon monoxide |
| DAS | data acquisition system |
| DOE | United States Department of Energy |
| ECEM | extractive continuous emissions monitor |
| EPA | Environmental Protection Agency |
| F | Fahrenheit |
| FC | fixed carbon |
| FWEC | Foster Wheeler Energy Corporation |
| H | hydrogen |
| HHV | higher heating value |
| ICCT | Innovative Clean Coal Technology |
| lb(s) | pound(s) |
| LNB | low NOx burner |
| LOI | loss on ignition |
| (M)Btu | (million) British thermal unit |
| MW | megawatt |
| N | nitrogen |
| NOx | nitrogen oxides |
| O, $O_2$ | oxygen |
| psig | pounds per square inch gauge |
| PTC | Performance Test Codes |
| RSD | relative standard deviation |
| S | sulfur |
| SCS | Southern Company Services |
| $SO_2$ | sulfur dioxide |
| UARG | Utility Air Regulatory Group |
| VM | volatile matter |

## INTRODUCTION

This paper discusses the technical progress of one of the U. S. Department of Energy's Innovative Clean Coal Technology (ICCT) projects demonstrating advanced combustion techniques for the reduction of nitrogen oxide (NOx) emissions from wall-fired boilers. This demonstration is being conducted on Georgia Power Company's Plant Hammond Unit 4. a 500 MW, pre-NSPS (New Source Performance Standards), wall-fired boiler. Plant Hammond is located near Rome, Georgia, northwest of Atlanta.

This project is being managed by Southern Company Services, Inc. (SCS) on behalf of the project co-funders: The Southern electric system, the U. S. Department of Energy (DOE), and the Electric Power Research Institute (EPRI). In addition to SCS, Southern includes the five electric operating companies: Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Savannah Electric and Power. SCS provides engineering and research services to the Southern electric system. The ICCT program is a jointly funded effort between DOE and industry to move the most promising advanced coal-based technologies from the research and development (R&D) stage to the commercial marketplace. The ICCT program sponsors projects that are different from traditional R&D programs that focus on long range, high risk, high payoff technologies with the DOE providing the majority of the funding. In contrast, the goal of ICCT projects is the demonstration of commercially feasible, advanced coal-based technologies that have already reached the "proof-of-concept" stage. The ICCT projects are jointly funded endeavors between the government and the private sector in which the industrial participant contributes at least 50 percent of the total project cost.

The primary objective of this demonstration is to determine the long-term effects of commercially available low NOx combustion technologies on NOx emissions and boiler performance. Short-term tests of each technology are also being performed to provide engineering information about emissions and performance trends. Achieving 50 percent NOx reduction using combustion modifications is the goal of this project. Specifically, the objectives of the project are listed below:

1. Demonstrate in a logical stepwise fashion the short-term NOx reduction capabilities of the advanced low NOx combustion technologies including advanced overfire air (AOFA), low NOx burners (LNB), and LNB with AOFA.

2. Determine the dynamic long-term emissions characteristics of each of these combustion NOx reduction methods using sophisticated statistical techniques.

3. Evaluate the progressive cost effectiveness (i.e., dollars per ton NOx removed) of the low NOx combustion techniques tested.

4. Determine the effects on other combustion parameters (e.g., CO production, carbon carryover, particulate characteristics) of applying the NOx reduction methods listed above.

## PROJECT DESCRIPTION

The stepwise approach to evaluating the NOx control technologies requires that plant outages be used to successively install the low NOx burner technologies. Table 1 shows the schedule for the installation of the equipment and test activities.

Following each outage, a series of four groups of tests are performed. These tests are (1) diagnostic, (2) performance, (3) long-term, and (4) verification. The diagnostic, performance, and verification tests consist of short-term data collection during carefully established operating conditions. The one- to four-hour diagnostic tests are designed to map the effects of changes in boiler operation on NOx emissions. The ten- to twelve-hour performance tests evaluate a more comprehensive set of boiler and combustion performance indicators. The results from these tests include particulate characteristics, boiler efficiency (consistent with ASME PTC 4.1), and boiler outlet emissions. Coal pulverizer (mill) performance and air flow distribution are also tested. The verification tests are used to characterize any changes that might have occurred during long-term testing.

| Installation and Test Schedule | | |
|---|---|---|
| Phase | Activity | Completion |
| Baseline | Install instrumentation | 10/89 |
| | Diagnostic & performance tests | 12/89 |
| | Long-term tests | 2/90 |
| | Verification tests | 3/90 |
| AOFA | Installation | 5/90 |
| | Diagnostic & performance tests | 8/90 |
| | Long-term tests | 3/91 |
| | Verification tests | 2/91 |
| LNB | Installation | 5/91 |
| | Diagnostic & performance tests | 8/91 |
| | Long-term tests | 12/91 |
| | Verification tests | 1/92 |
| LNB + AOFA | Diagnostic & performance tests | 1/93 |
| | Long-term tests | 3/93 |
| | Verification | 3/93 |

**Table 1. Installation and Test Schedule**

As stated previously, the primary objective of the demonstrations is to collect long-term, statistically significant quantities of data under normal load-dispatched operating conditions with and without the various NOx reduction technologies. Earlier demonstrations of emissions control technologies have relied solely on data from a matrix of carefully established short-term (one- to four-hour) tests. However, boilers are not typically operated in this manner considering plant equipment inconsistencies and economic dispatch strategies. Therefore, statistical analysis methods [1] for long-term data have been developed that can be used to determine the achievable emissions limit or emission tonnage of a control technology. These analysis methods have been developed over the past fifteen years by the Control Technology Committee of the Utility Air Regulatory Group (UARG). Because the uncertainty in the analysis methods is reduced with increasing data set size, UARG recommends that acceptable results can be achieved with data sets of at least 51 days with each day containing at least 18 valid hourly averages.

The demonstration of these low NOx burner technologies requires an on-line data acquisition system and continuous emissions monitor that collects, formats, calculates, stores, and transmits data from power plant mechanical, thermal, and fluid processes [2]. This system monitors emissions of NOx, $SO_2$, $O_2$, CO, and total hydrocarbons.

## UNIT DESCRIPTION

Georgia Power Company's Plant Hammond Unit 4 (Figure 1) is a Foster Wheeler Energy Corporation (FWEC) opposed wall-fired boiler, rated at 500 gross MW, with design steam conditions of 2500 psig and 1000/1000°F superheat/reheat temperatures, respectively. The unit was placed into commercial operation on December 14, 1970. Prior to the LNB retrofit, six FWEC Planetary Roller and Table type mills provided pulverized eastern bituminous coal (12,900 Btu/lb, 33% VM, 53% FC, 1.7% S, 1.4% N) to 24 pre-NSPS, Intervane burners. During the LNB outage, the existing burners were replaced with FWEC Control Flow/Split Flame burners. The unit was also retrofit with four Babcock and Wilcox MPS 75 mills during the course of the demonstration. The burners are arranged in a matrix of 12 burners (4W x 3H) on opposing walls with each mill supplying coal to 4 burners per elevation. As part of this demonstration project, the unit was retrofitted with an Advanced Overfire Air System, to be described later. The unit is equipped with a coldside ESP and utilizes two regenerative secondary air preheaters and two regenerative primary air heaters. The unit was designed for pressurized furnace operation but was converted to balanced draft operation in 1977.

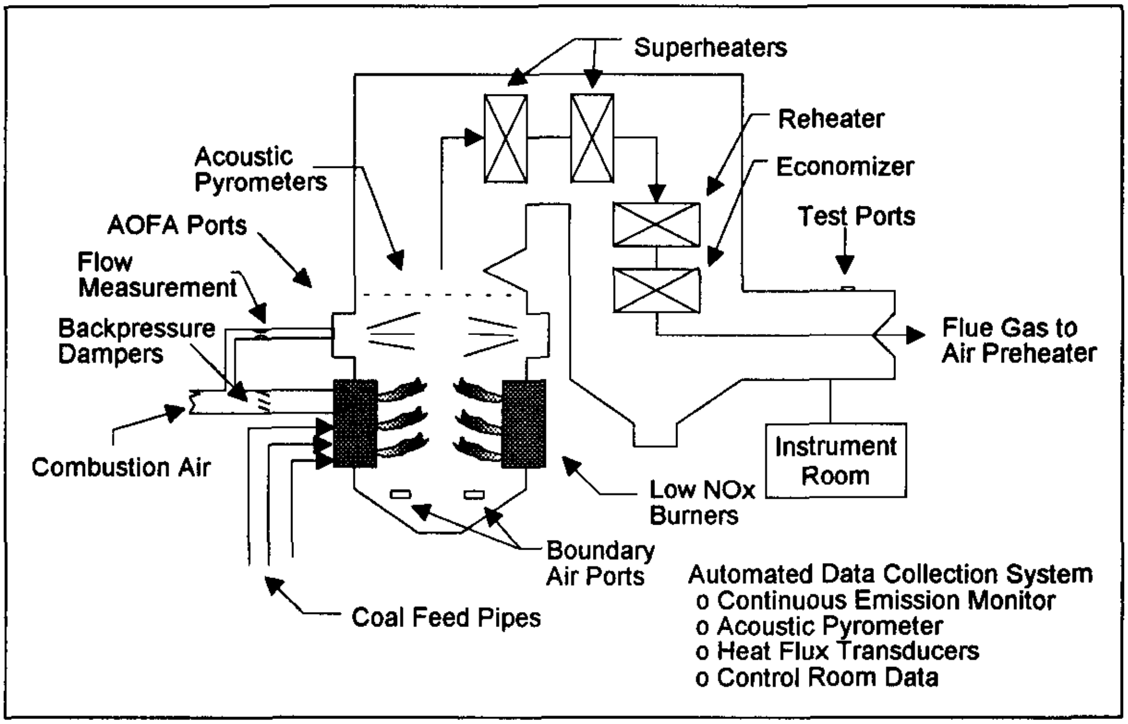


**Figure 1. Boiler Schematic**

## LOW NOx COMBUSTION TECHNOLOGIES

### Advanced Overfire Air

Generally, combustion NOx reduction techniques attempt to stage the introduction of oxygen into the furnace. This staging reduces NOx production by creating a delay in fuel and air mixing which lowers combustion temperatures. The staging also reduces the quantity of oxygen available to the fuel-bound nitrogen. Typical overfire air (OFA) systems accomplish this staging by diverting 10 to 20 percent of the total combustion air to ports located above the primary combustion zone. AOFA improves this concept by introducing the OFA through separate ductwork in greater quantities, with more control, and at higher pressures (Figure 2). The resulting system is capable of providing deep staging of the combustion process with accurate measurement of the AOFA airflow.

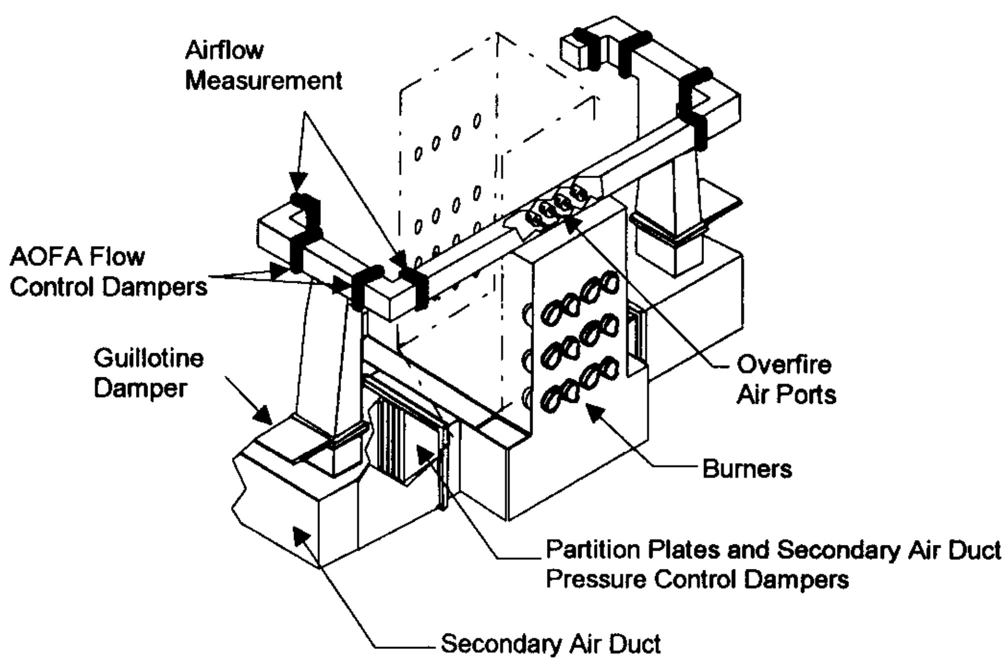


**Figure 2. Advanced Overfire Air System**

Low NOx Burners

Low NOx burner systems attempt to stage the combustion without the need for the additional ductwork and furnace ports required by OFA and AOFA systems. These commercially available burner systems introduce the air and coal into the furnace in a well controlled, reduced turbulence manner. To achieve this, the burner must regulate the initial fuel/air mixture, velocities and turbulence to create a fuel-rich core with sufficient air to sustain combustion at a severely sub-stoichiometric air/fuel ratio. The burner must then control the rate at which additional air, necessary to complete combustion, is mixed with the flame solids and gases to maintain a deficiency of oxygen until the remaining combustibles fall below the peak NOx producing temperature (around 2800°F). The final excess air can then be allowed to mix with the unburned products so that the combustion is completed at lower temperatures. Low NOx burners have been developed for single wall and opposed wall boilers.

Foster Wheeler Energy Corporation (FWEC) was competitively selected to design, fabricate, and install the opposed wall, low NOx burner shown in Figure 3 and the AOFA system described above. In the FWEC Controlled Flow/Split Flame (CFSF) burner, secondary combustion air is divided between inner and outer flow cylinders. A sliding sleeve damper regulates the total secondary air flow entering the burner and is used to balance the burner air flow distribution. An adjustable outer register assembly divides the burner's secondary air into two concentric paths and also imparts some swirl to the air streams. The secondary air that traverses the inner path flows across an adjustable inner register assembly that, by providing a variable pressure drop, apportions the flow between the inner and outer flow paths. The inner register also controls the degree of additional swirl imparted to the coal/air mixture in the near throat region. The outer air flow enters the furnace axially, providing the remaining air necessary to complete combustion. An axially movable inner sleeve tip provides a means for varying the primary air velocity while maintaining a constant primary flow. The split flame nozzle segregates the coal/air mixture into four concentrated streams, each of which forms an individual flame when entering the furnace. This segregation minimizes mixing between the coal and the primary air, assisting in the staged combustion process. The adjustments to the sleeve dampers, inner registers, outer registers, and tip position are made during the burner optimization process and thereafter remain fixed unless changes in plant operation or equipment condition dictate further adjustments.

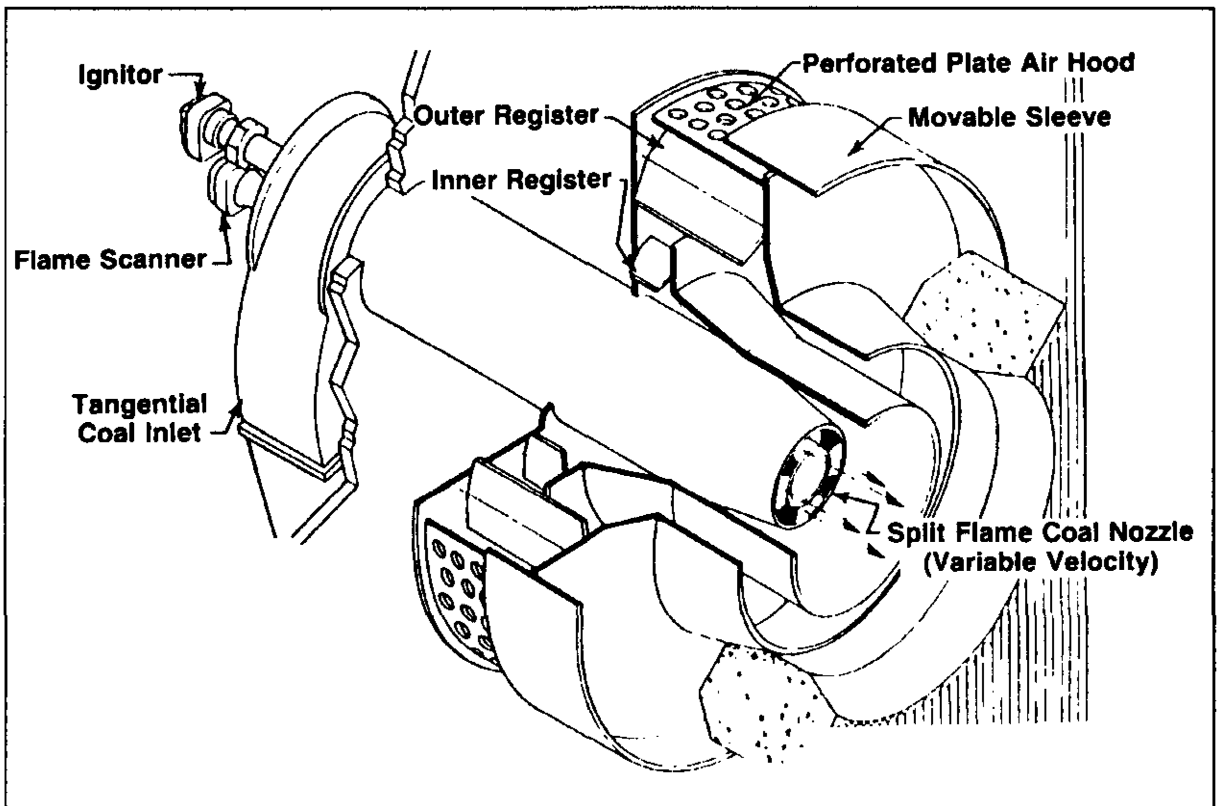


**Figure 3. Low NOx Burner Installed at Plant Hammond**

## RETROFIT REQUIREMENTS

### Advanced Overfire Air Retrofit

During April 1990, the AOFA system was installed at the demonstration site. The majority of the work was performed during the scheduled four-week outage starting April 5, 1990, with only insulation, handrails, and controls setup work left for on-line completion. During the outage, the construction subcontractor worked two, ten-hour shifts per day, six days per week. Radiography was performed on all pressure welds between the night and morning shifts. At peak work levels, the construction subcontractor employed approximately 130 craft personnel. However, very early in the outage, a shortage of certified craft personnel became evident. This shortage, which was a result of several concurrent boiler outages at other sites in the area, created scheduling difficulties throughout the outage.

### LNB Retrofit

The new LNBs were installed during a seven week outage starting March 8, 1991, and continuing to April 28, 1991. Prior to the outage, rigging was installed, access pathways were formed, and when possible, insulation and lagging were removed. As would be the case with any work of this nature, installation of the new FWEC burners was far from simple. Although no pressure part modifications were required, complicating factors included limited boiler access, craft labor shortages, the presence of asbestos, unacceptable levels of arsenic in the boiler, and the requirement to coordinate with the many other work activities occurring at the plant during a major outage. Thirty craft personnel were involved in the retrofit, working a single, ten-hour shift, six days a week for four weeks and two, ten-hour shifts, six days a week for the remaining three weeks.

Operating performance of the low NOx burners is dependent on a number of plant operating parameters such as primary air/fuel ratios, secondary air distribution, primary air velocities, and coal properties and therefore these burners must be "tuned" for the particular boiler application. Optimization of the burners for NOx reduction was performed by FWEC personnel during a three week period in June. The optimization required that the unit be taken out of economic dispatch and run at full-load for much of the optimization period. After balancing the secondary air flows, the burner optimization process was accomplished by adjusting the inner registers, outer registers, slide nozzles, and sleeve dampers while monitoring NOx, $O_2$, and CO at the economizer outlet using the ECEM and DAS. When possible, burner adjustments of the same class (the classes being inner register, outer register, slide nozzle, and sleeve damper) were moved in unison to a nominal, optimized position. Only when flow and/or combustion irregularities dictated, were individual dampers adjusted from this nominal position.

## RESULTS DISCUSSIONS

### Baseline Testing Summary

Baseline tests at Plant Hammond were completed in March 1990. A summary of the baseline long-term test results is shown in Table 2. During baseline testing, 52 days of long-term data were collected producing an average NOx emission level of 1.12 lb/MBtu. Figure 4 shows that NOx emissions increased with load and ranged from 0.9 to 1.3 lb/MBtu. The bands about the mean represent the 95 percentiles of the data set and show the variability of NOx emissions during long-term operation.

### AOFA Test Summary

Advanced overfire air tests at Plant Hammond (with the pre-NSPS Intervane burners still in operation) were completed in March 1991. A summary of the long-term test results is shown along with the baseline results in Table 2. During AOFA testing, 86 days of long-term data were collected for which the average NOx emission level was 0.92 lb/MBtu. This represents an 18 percent reduction in average NOx emissions from baseline conditions. As compared to the baseline characteristic, NOx emissions were not highly dependent on load during the AOFA test phase (Figure 5).

### LNB Test Summary

Low NOx burner tests at Plant Hammond were completed in January 1992. For this phase, the unit was operated without the AOFA system so that the incremental impact of the LNBs could be determined. As shown in Table 2 and Figure 6, 94 days of long-term data were collected for which the average NOx emission level was 0.53 lb/MBtu and the full load (480 MW), mean, NOx emission level was 0.65 lb/MBtu. NOx emissions generally increased with load, however below approximately 250 MW, the converse was true. Although a small percentage (less than 5 percent) of the total combustion air was admitted into the furnace through the AOFA ports to cool the AOFA dampers, preliminary results indicate that this cooling air did not significantly affect NOx emissions.

LNB+AOFA Test Summary

Comprehensive testing of the LNBs in conjunction with AOFA is scheduled to start in fall 1992. However, in order to provide preliminary data, abbreviated testing (short- and long-term) of the LNB+AOFA configuration was performed at Plant Hammond from February to March 1992, during which approximately one week of long-term data was collected. As shown in Figure 7, long-term NOx emissions were somewhat independent of load above 275 MW. However, below this load, NOx emissions increased rapidly. The decrease in effectiveness of this configuration at low loads is the result of the operating procedures calling for the closure of AOFA dampers below 300 MW.

| Unit Configuration | Baseline | | AOFA | | LNB | |
|---|---|---|---|---|---|---|
| | Mean | RSD,% | Mean | RSD,% | Mean | RSD,% |
| Number of Daily Averaged Values | 52 | - | 86 | - | 94 | - |
| Average Load (MW) | 407 | 9.4 | 386 | 17.9 | 305 | 17.7 |
| Average NOx Emissions (lb/MBtu) | 1.12 | 9.5 | 0.92 | 8.6 | 0.53 | 13.7 |
| Average O2 Level (percent at stack) | 5.8 | 11.7 | 7.3 | 12.6 | 8.4 | 7.7 |
| NOx 30 Day Achievable Emission Limit (lb/MBtu) | 1.24 | - | 1.03 | - | 0.64 | - |
| NOx Annual Achievable Emission Limit (lb MBtu) | 1.13 | - | 0.93 | - | 0.55 | - |

**Table 2. Long-Term NOx Emissions**

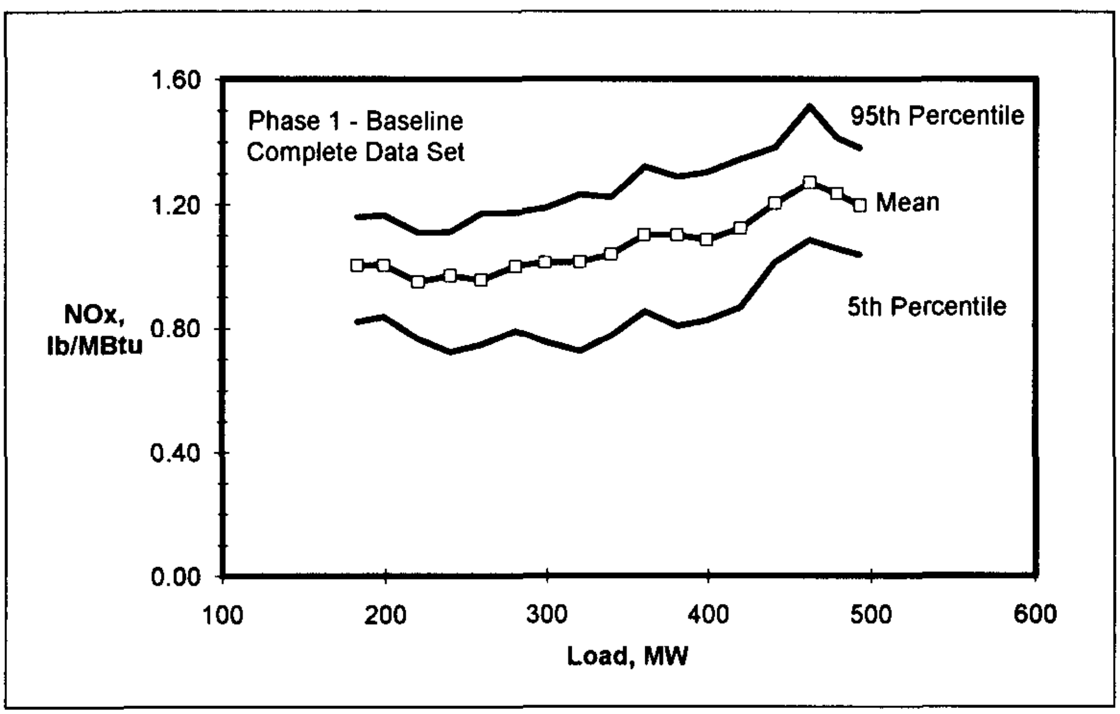


**Figure 4. Baseline Long-Term NOx Emissions**

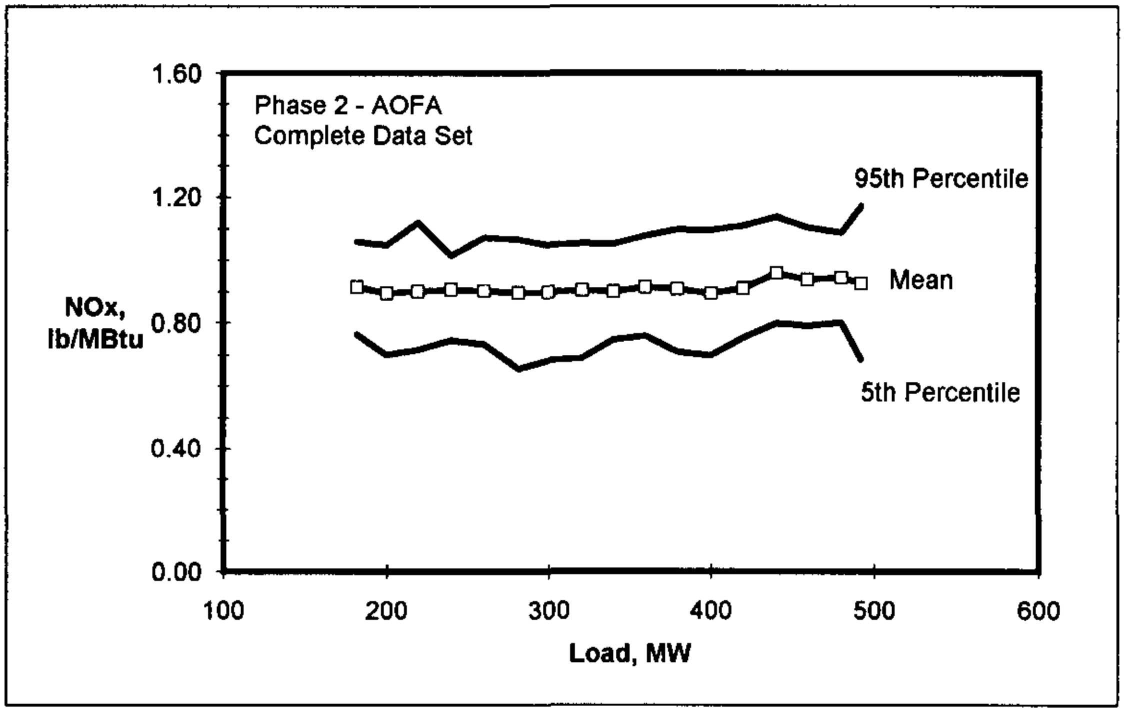


**Figure 5. AOFA Long-Term NOx Emissions**

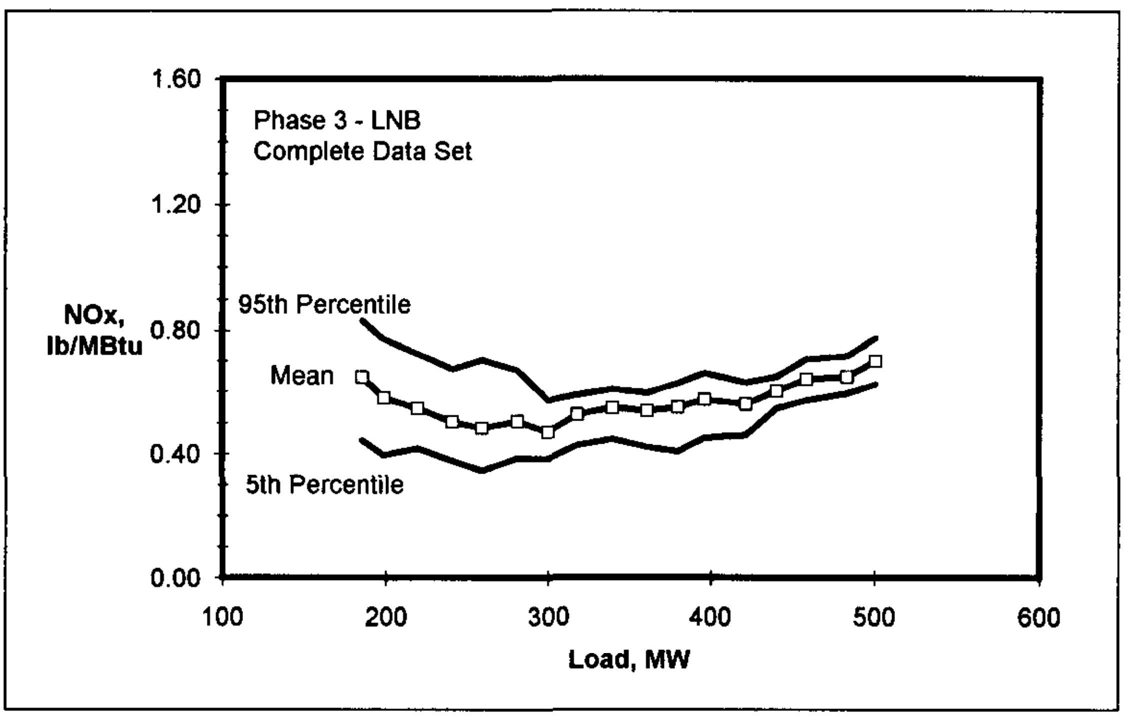


**Figure 6. LNB Long-Term NOx Emissions**

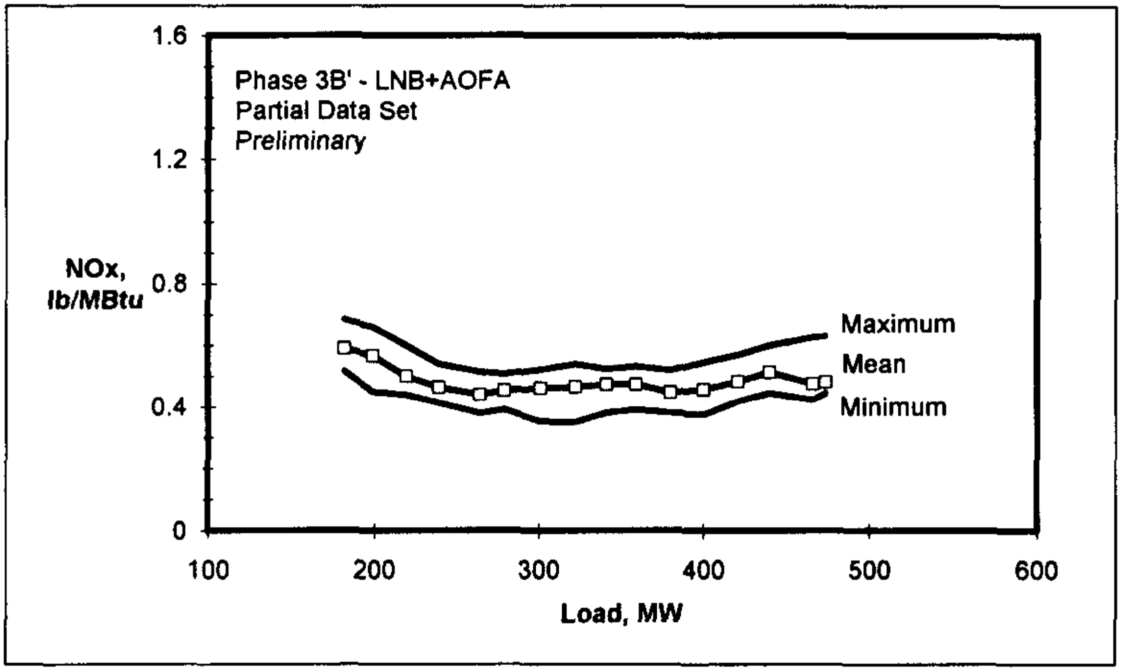


**Figure 7. LNB+AOFA Long-Term NOx Emissions (Preliminary)**

Data Comparison

Figure 8 compares the baseline, AOFA, LNB and LNB+AOFA short- and long-term NOx emissions data. AOFA and LNBs provide a long-term, full load NOx reduction of 24 and 48 percent, respectively. Although the abbreviated long-term testing of the LNB+AOFA configuration performed to date does not provide sufficient data to fully characterize NOx emissions at full-load, the incremental percent NOx reduction of the combined LNB+AOFA system above LNB alone has averaged less than 10 percent over the load range. As shown, long-term emission levels can be significantly different than that indicated by short-term tests.

Flyash loss-on-ignition (LOI) values increased significantly for both the AOFA, LNB and LNB+AOFA test phases (Figure 9). LOI measurements for the baseline, AOFA, and LNB test segments were made during each performance test using EPA's Method 17 at the secondary air heater outlet. High volume sampling was used for the abbreviated LNB+AOFA phase. Mill performance was generally better in both the AOFA, LNB, and LNB+AOFA test phases than during baseline (Table 3). This improvement in mill performance was the result of the plant's ongoing mill maintenance program and the installation of the new mills.

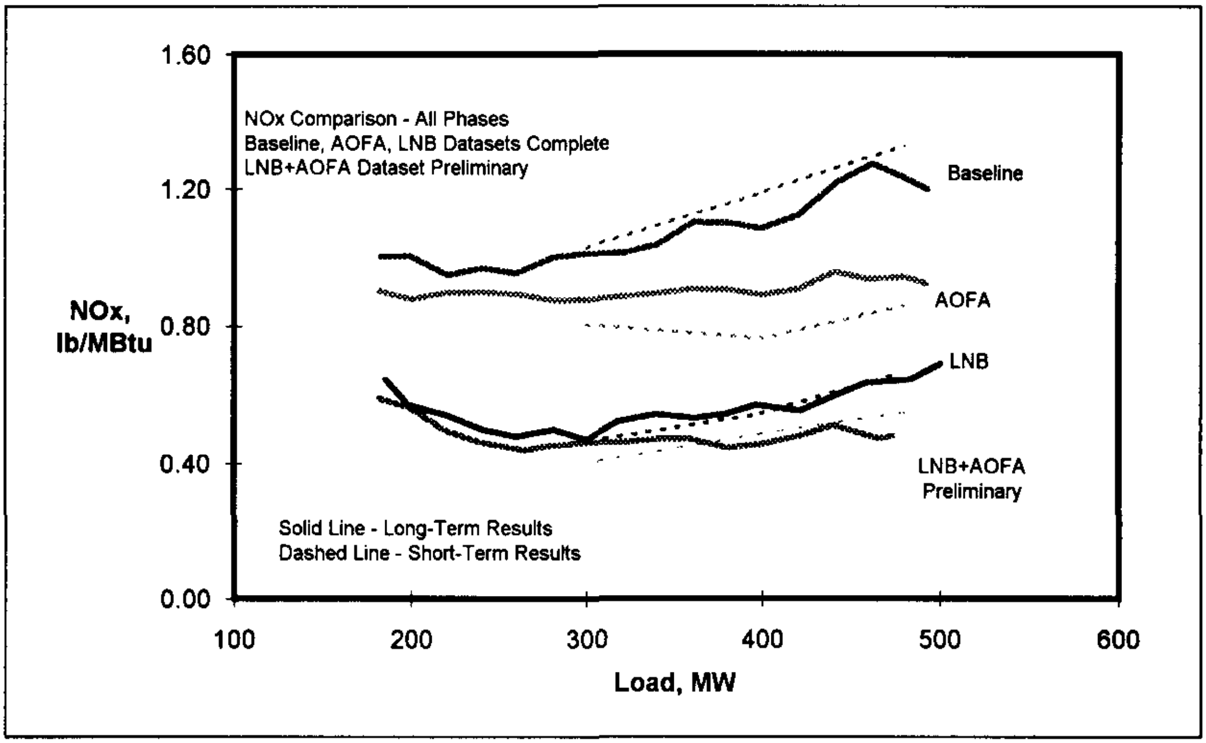


**Figure 8. NOx Emissions Comparison**

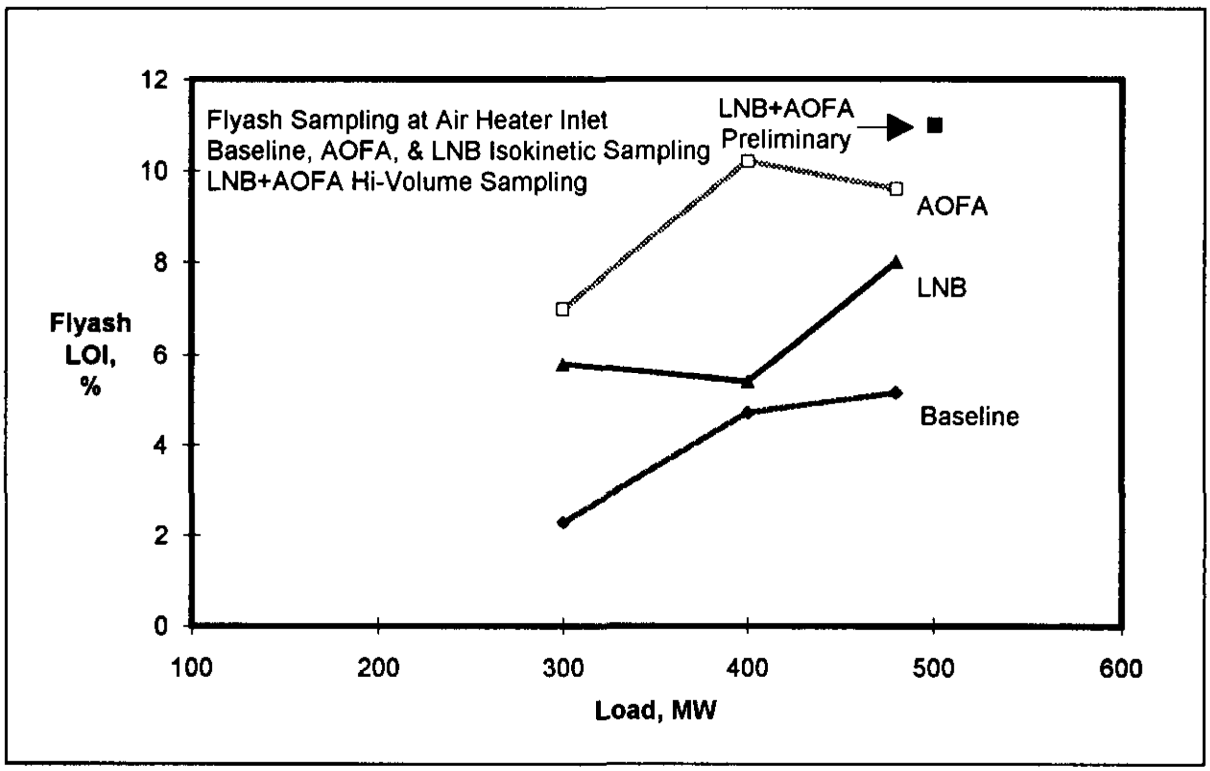


**Figure 9. Flyash Loss-On-Ignition Comparison**

| Mill Performance at Full Load<br>Mill Coal Flow Weighted Averages | | |
|---|---|---|
| Phase | Left on 50 Mesh<br>Percent | Passing 200 Mesh<br>Percent |
| Baseline | 2.8 | 63.0 |
| AOFA | 2.6 | 66.5 |
| LNB | 1.3 | 66.5 |
| LNB+AOFA[1] | 1.3 | 73.6 |

[1]Preliminary

**Table 3. Mill Performance at Full Load**

An important segment of the test program is to determine the impact of the low NOx combustion technologies on boiler performance. Boiler efficiency testing is performed as part of the performance tests and follows guidelines set forth in ASME PTC 4.1 [3]. As shown in Table 4, boiler efficiency has been adversely impacted by the low NOx combustion technologies installed on Hammond 4. The major contributors to the loss of efficiency are: (1) an increase in combustion air requirements leading to increased dry flue gas losses and (2) higher carbon in ash values. The efficiency of the boiler is expected to decrease further when operating with LNBs in conjunction with AOFA.

| Full Load Boiler Efficiencies (Preliminary) | | | | | |
|---|---|---|---|---|---|
| Phase | Efficiency | | | | |
| | Test 1 | Test 2 | Test 3 | Average | Percent Decrease |
| Baseline | 90.0 | 89.7 | 89.7 | 89.8 | - |
| AOFA | 89.3 | 89.3 | 89.1 | 89.2 | 0.6 |
| LNB | 87.4 | 88.5 | 88.4 | 88.1 | 1.6 |

**Table 4. Full Load Boiler Efficiencies (Preliminary)**

As shown in Figure 10, baseline CO emissions were highly dependent on load, increasing from approximately 10 ppm at minimum load to 100 ppm at full load. This dependency was not evident in either the long-term AOFA, LNB, or LNB+AOFA testing, for which maximum CO values were approximately 20 ppm. This change is probably attributable to plant operating personnel beginning to monitor CO emission levels and taking action to reduce these emissions. Prior to the AOFA long-term test phase, CO emission levels were not displayed in the control room.

Full load, long-term, stack $O_2$ levels for the LNB and LNB+AOFA test phases were approximately 30 percent higher than the corresponding baseline values (Figure 11). This change in $O_2$ level for the LNB and LNB+AOFA tests is mostly attributable to an increase of approximately 5 to 10 percent in combustion air requirements for these configurations. Although an increase in the stack $O_2$ is indicated in this figure, the combustion air to the furnace did not change appreciably between the baseline and AOFA test phase - the change in $O_2$ levels were caused primarily by leakage in the furnace backpass. This leakage was repaired during the low NOx burner installation outage. The impact of this leakage and varying $O_2$ levels on emissions and unit performance will be investigated and discussed in future reports.

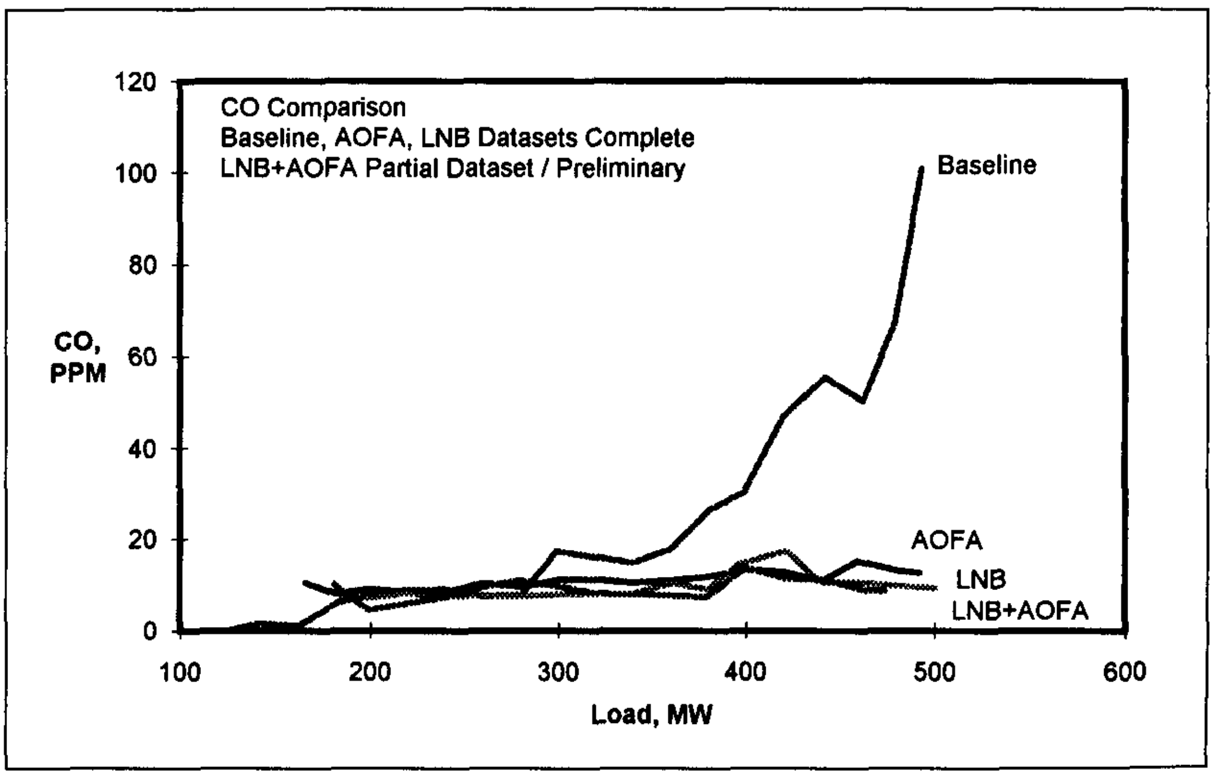


**Figure 10. CO Levels Comparison**

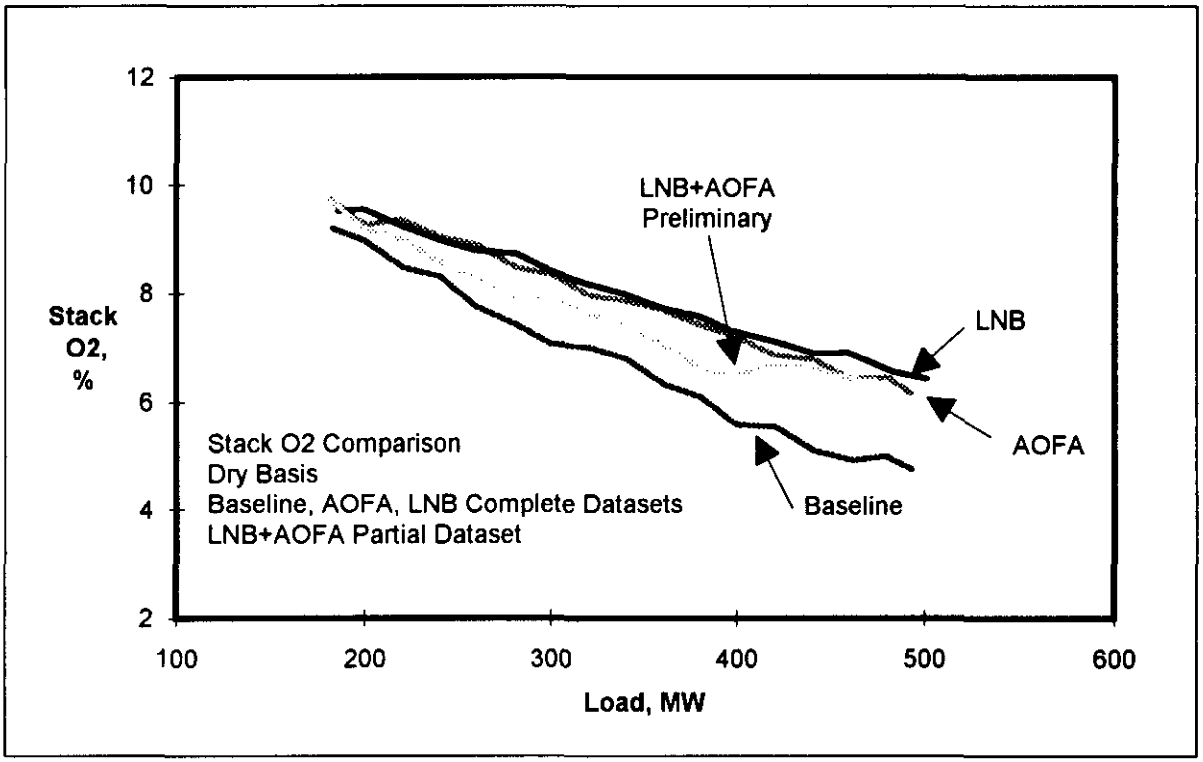


**Figure 11. $O_2$ Levels Comparison**

Unit Operations

An unexpected consequence of the installation of the LNBs was a decrease in furnace slagging and an increase in precipitator particulate mass loading and gas flow rates. As shown in Table 5, the post-LNB retrofit increases in particulate mass loading and gas flow rate were approximately 25 percent and 11 percent, respectively. The post-AOFA retrofit gas flow rate was approximately 17 percent greater than baseline, however most of this change is due to air in-leakage in the furnace backpass and is not attributable to increased combustion air requirements. For the LNB test phase, combustion air requirements did rise. A side effect of the post-retrofit shift in ash loading has been a post-LNB retrofit rise in primary air heater plugging rates. These increases, coupled with the higher post-LNB retrofit flyash LOI, adversely impacted particulate emissions such that it was necessary to run the unit at reduced loads to meet particulate compliance limits. Ammonia flue gas conditioning was used to improve precipitator collection efficiency, allowing full load operation and the completion of the LNB test phase.

| ESP Inlet Conditions | | | | |
|---|---|---|---|---|
| | Mass Loading | | Gas Flow | |
| | Gr/SCF | Change | ACFM | Change |
| Phase | | % | | % |
| Baseline | 1.58 | - | 1.99E+06 | - |
| AOFA | 1.68 | 5 | 2.29E+06 | 17 |
| LNB | 1.96 | 25 | 2.21E+06 | 11 |

Gr/SCF = Grains per standard cubic feet
ACFM = Actual cubic feet / minute
Percent change is relative to baseline

**Table 5. ESP Inlet Conditions**

Testing performed by Georgia Power Company in July 1992, indicated that stack particulate emissions had increased. The unit was tested in the LNB+AOFA configuration with the ammonia flue gas conditioning system in service. To meet particulate compliance limits, the unit is again running at reduced loads until resolution of the particulate emissions issues.

Reliability

Three low NOx burners have failed due to excessive heat since the spring 1991 low NOx burner retrofit. In all of these failures, portions of the cast burner nozzle assembly melted away, especially in the vicinity of the coal nozzle. These burners have failed on both the new Babcock and Wilcox mills and the FWEC mills, front and rear furnace walls, and upper and lower burner elevations (Figure 12). Two of these failures have occurred since the resumption of unit operation following the spring 1992 outage. The last and most severe of the three burner failures, occurred on June 16, 1992, and required a one week outage to repair. Damage in this instance was not limited to the cast burner nozzle and sliding tip assembly, but also included the inner and outer barrel, secondary air register, adjacent burners, and windbox. Since this failure, an enhanced burner thermocouple monitoring system has been installed to provide more comprehensive alarming capabilities.

Inspection of the burners during the spring 1992 outage revealed cracks in 17 of the 24 burner cast tips. The cracks are most severe on the upper elevation of burners. In many instances, the cracks were several inches long with multiple cracks on each tip. At this time, the cracks do not seem to impact performance and FWEC recommends that no corrective action be taken. An investigation into this cracking has been undertaken by DOE's Oak Ridge National Laboratory.

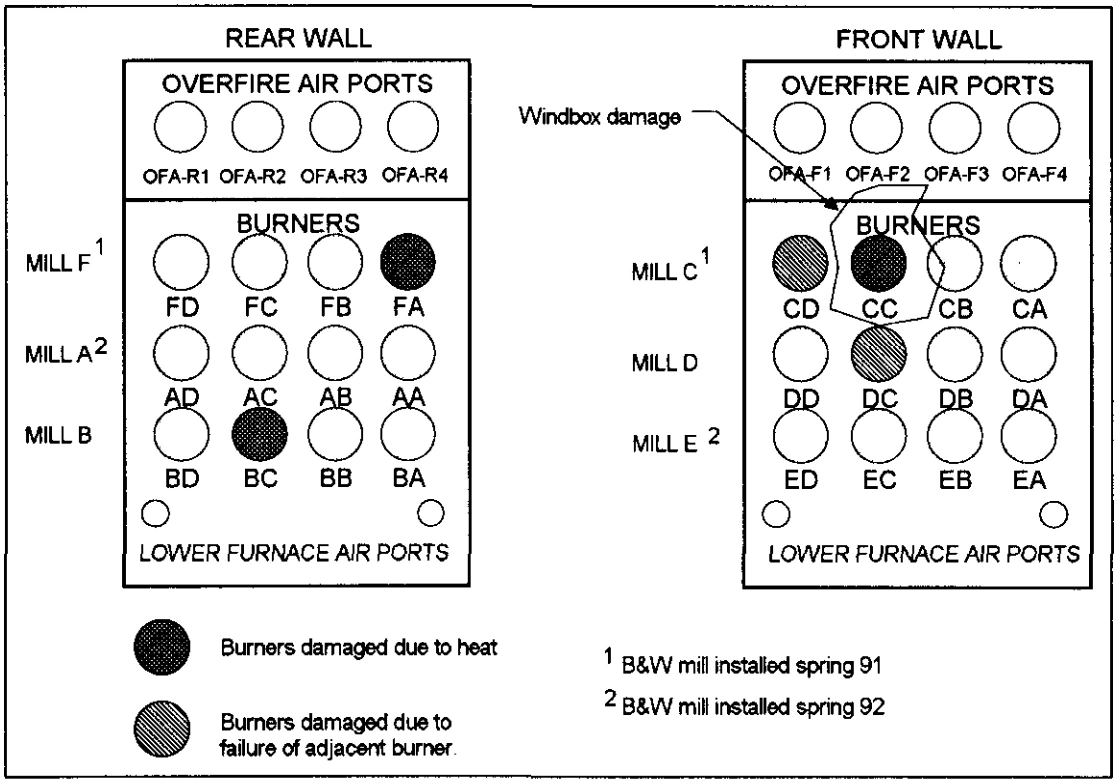


**Figure 12. Damaged Burner Locations**

## CONCLUSIONS

In conclusion, the results to date at Plant Hammond indicate:

- NOx emissions have been reduced to near 50 percent of baseline values by using low NOx burners alone. These reductions were sustainable over the long-term test period and were consistent over the entire load range. Furnace waterwall slagging has been significantly reduced, leading to a reduction in soot-blowing frequency. Unit operation was approximately the same or slightly better than that experienced during baseline testing.

- Preliminary results show that AOFA used in conjunction with the LNBs provide only marginal, incremental NOx reduction benefits averaging less than 10 percent over the load range. When compared to baseline, the full load NOx reduction in this configuration is approximately 55 percent. The full load NOx reduction using AOFA alone was approximately 24 percent. Operation of the unit was also more difficult when using the AOFA system.

- In the AOFA, LNB, and LNB+AOFA configurations, the unit experienced significant performance impacts including increases in excess air and carbon in flyash.

- *The burners are susceptible to tip cracking and meltdowns. These problems will* impact reliability and may affect performance as it relates to NOx production and LOI. Future work should address these challenges and the controls necessary to maintain performance and reliability.

- Auxiliary systems can be adversely impacted by the installation of these combustion technologies. Precipitator mass loading and gas flow rates have increased. Excess air requirements, and therefore fan power requirements, have also increased.

## ACKNOWLEDGMENTS

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1 Smith, L. L., Pitts, III, W. S., Rush, R., Flora, T., "Long-Term Versus Short-Term Data Analysis Methodologies," 1987 Symposium of Stationary Combustion NOx Control, New Orleans, Louisiana, March 23-26, 1987.

2 Sorge, J. N., Hardman, R. R., Wilson, S. M., "Demonstration of Advanced Wall- and Tangentially-Fired Combustion Modifications for the Reduction of Nitrogen Oxide (NOx) Emissions from Coal-Fired Boilers," Joint American Flame Research Council/Japanese Flame Research Council International Conference on Environmental Control of Combustion Processes, Honolulu, Hawaii, October 7-10, 1991.

3 ASME Performance Test Codes, PTC 4.1, "Steam Generating Units," New York: American Society of Mechanical Engineers, latest edition.

# 180 MW TANGENTIALLY-FIRED LOW NOx BURNER DEMONSTRATION

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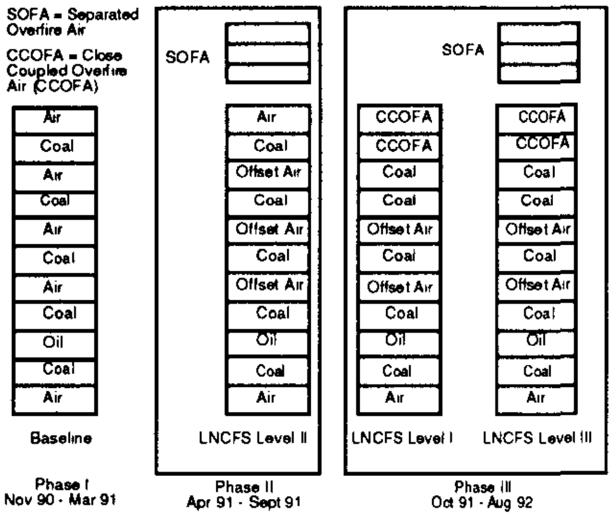
## ABSTRACT

This paper discusses the technical progress of a U. S. Department of Energy Innovative Clean Coal Technology project demonstrating advanced tangentially-fired (T-fired) combustion techniques for the reduction of nitrogen oxide (NOx) emissions from coal-fired boilers. The primary objective of this demonstration is to determine the performance of different low NOx combustion technologies applied in a stepwise fashion to a 180 MW T-fired boiler. A description of the low NOx combustion technologies, retrofit requirements, and NOx emissions results are discussed. The effects of operating with the low NOx combustion systems are also presented.

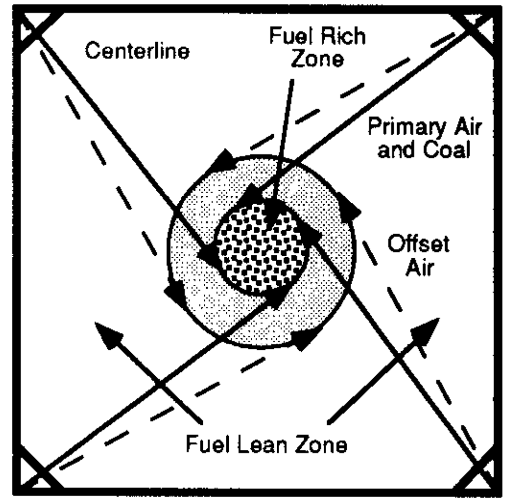
Based on results to date, NOx emissions have been reduced by as much as 40 percent with minimal impacts on boiler operation, carbon loss, or carbon monoxide production. NOx emissions can be reduced by as much as 48 percent with a nominal increase in flyash carbon content. All of the technologies tested have reduced full load NOx emissions below the presumptive standard (0.45 lb/MBtu) for T-fired boilers.

## TABLE OF ABBREVIATIONS

| | |
|---|---|
| ABB CE | Asea Brown Boveri Combustion Engineering Services |
| ASME | American Society of Mechanical Engineers |
| CCOFA | close coupled overfire air |
| C | carbon |
| Cl | chlorine |
| CO | carbon monoxide |
| DOE | United States Department of Energy |
| ECEM | extractive continuous emissions monitor |
| EPA | Environmental Protection Agency |
| F | Fahrenheit |
| FC | fixed carbon |
| H | hydrogen |
| HHV | higher heating value |
| H2O | water |
| ICCT | Innovative Clean Coal Technology |
| lb(s) | pound(s) |
| LNCFS | Low NOx Concentric Firing System |
| LOI | loss on ignition |
| (M)Btu | (million) British thermal unit |
| MW | megawatt |
| N | nitrogen |
| NOx | nitrogen oxides |
| O, O2 | oxygen |
| psig | pounds per square inch gauge |
| PTC | Performance Test Codes |
| recom | recommended |
| RSD | relative standard deviation |
| S | sulfur |
| SCS | Southern Company Services |
| SO2 | sulfur dioxide |
| SOFA | separated overfire air |
| T-fired | tangentially-fired |
| UARG | Utility Air Regulatory Group |
| VM | volatile matter |




LNCFS Levels I, II, and III




Concentric Firing Concept

Fig. 2. Low NOx Concentric Firing System Levels I, II, and III and the Concentric Firing Concept.

## RETROFIT REQUIREMENTS

### LNCFS Level II

The installation of LNCFS Level II required a three week outage that began on March 29, 1991. During that outage, craft laborers worked seven days a week with two ten-hour shifts per day. The remaining four hours of the day were reserved for x-raying welds in the furnace walls. During peak work loads, as many as 70 craft laborers per shift were involved in the retrofit. A full furnace scaffold was installed to expedite the job.

Due to the scope of the work required to be performed during the outage, the SOFA ductwork was hung in place prior to the unit coming off line. The installation of the SOFA windboxes required significant pressure part modifications to each corner of the boiler above the main windbox. Preassembled bent tube panels were welded into the four 10 feet high by 4 feet wide holes cut in the boiler. The SOFA windboxes with three sets of air nozzles were inserted into the 5 feet high by 2 feet wide openings in the tube panels. Each nozzle has its own automatically controlled damper to regulate the flow to the SOFA ports. The yaw adjustment on each SOFA nozzle is manually adjustable. The three nozzles tilt in unison via automatic controls linked to the tilting of the nozzles in the main windbox.

The critical path for this outage was the modification to the main windboxes. The windboxes were completely stripped of coal nozzles, auxiliary air nozzles, tilt linkages, and all bearings and bushings. After removing this equipment, the partition plates and windbox turning vanes were inspected for warpage and wear. When necessary, these parts were replaced or refurbished. Additional partition plates were installed in the top and bottom auxiliary air compartments. All of the partition plates were cut back approximately three inches to allow greater tilting mobility of the new coal and air nozzles. All coal nozzles and tips were replaced, Rockwell couplings were installed in the fuel lines to relieve fuel pipe loadings on the windbox, and four elevations of flame scanners were installed including a cooling air system with a dedicated fan. The windbox tilting mechanism was completely replaced. The offset air nozzles in the main windbox have the capability to move in the horizontal direction by a manual adjustment. The air and coal nozzles tilt in unison via automatic controls.

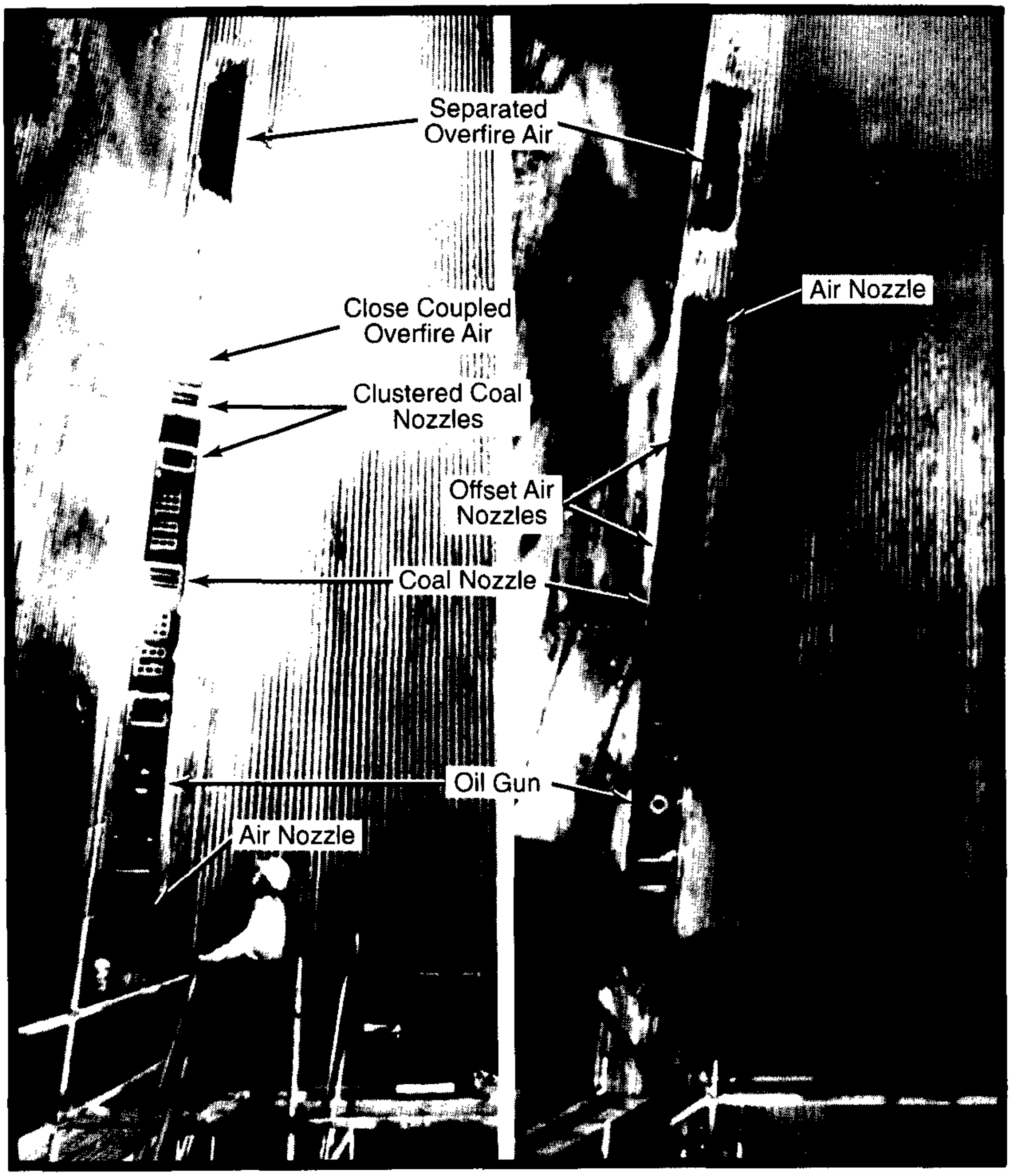
The right half of Figure 3 shows the arrangement and scale of the LNCFS Level II equipment. The bottom of the SOFA windbox is approximately 10 feet from the top of the main windbox. The locations of the coal and air nozzles remain unchanged in comparison with the baseline configuration.

LNCFS Level III

The previously installed LNCFS Level II was converted to LNCFS Level III during a two week outage that began in October 1991. Craft laborers worked five days a week with two ten-hour shifts per day. An average of 36 craft laborers per day was involved in the retrofit. A full furnace scaffold was utilized to expedite the job.

During the two week outage, the CCOFA air ports were installed in the top of the main windbox. This modification required the reconfiguration of the top three windbox compartments in each corner of the boiler. The existing coal compartment and the two auxiliary air compartments in the top of the windbox were replaced with one stationary auxiliary air compartment, one coal compartment and two CCOFA compartments. To facilitate the relocation of the coal nozzle to a lower elevation, coal piping, ignitors, flame scanners, and platform steel in each corner were also relocated.

The left half of Figure 3 shows the physical arrangement of LNCFS Level III. The locations of the coal and air nozzles in the bottom half of the windbox did not change with respect to the baseline configuration. The top coal nozzle in each corner has been switched with the air nozzle above it to




LNCFS Level III

LNCFS Level II

Fig. 3: NOx Control Technologies Installed in the Boiler Showing Arrangement of Coal and Air Nozzles.

provide space for an overfire air system in the main windbox. The resulting configuration is the CCOFA system in the top of the windbox with two clustered coal nozzles immediately below it.

## RESULTS DISCUSSION

Table 2 presents the long-term NOx emissions results for each phase of the project completed to date. LNCFS Level I long-term tests have not yet been completed. The technologies were tested during different seasons of the year. As a result, the average load during each phase is a function of the load requirements during that season. For example, LNCFS Level II tests were conducted during the summer months resulting in an average load of 172 MW. LNCFS Level III tests were conducted during the winter months resulting in an average load of only 141 MW. As discussed later in this paper, NOx emissions vary with unit load; therefore, the average load during any one phase has a significant impact on the average emissions level reported during that phase.

### Baseline Test Summary

Baseline tests were completed in March 1990. A summary of the baseline long-term test results is shown in Table 2. Seventy-five days of long-term data were collected generating an average NOx emission level of 0.62 lb/MBtu. Figure 4 shows that baseline NOx emissions decreased slightly with decreases in unit load and ranged from 0.64 lb/MBtu at full load to 0.55 lb/MBtu at minimum load. The bands about the mean represent the 95 percentiles of the data set. Ninety-five percent of the long-term data fall below the upper limit and 5 percent of the data fall below the lower limit. These limits show that NOx emissions varied by as much as 0.2 lb/MBtu at a given load during normal load-dispatched operations.

### LNCFS Level I Test Summary

The LNCFS Level I technology is being tested by closing the dampers of the SOFA system used for LNCFS Level III. In order to ensure the material integrity of the SOFA nozzles, a minimum amount of leakage flow is maintained through the SOFA ductwork. Based on measurements made during short-term tests, the leakage flow equates to approximately 4.4 percent of the total combustion air in the boiler. According to ABB CE, the effect of this leakage flow is to reduce NOx emissions below those of a true LNCFS Level I system. A correction factor is applied to the NOx emissions data to negate the leakage effects in the results.

| Unit Configuration | Baseline | | LNCFS II | | LNCFS III | |
|---|---|---|---|---|---|---|
| | Mean | RSD, % | Mean | RSD, % | Mean | RSD, % |
| Number of Daily Averaged Values | 75 | - | 55 | - | 71 | - |
| Average Load (MW) | 155 | 14.8 | 172 | 7.1 | 141 | 15.1 |
| Average Emissions | 0.62 | 5.8 | 0.41 | 6.9 | 0.39 | 9.7 |
| Average O2 Level at stack, percent | 6.55 | 11.6 | 6.50 | 8.8 | 7.56 | 7.8 |
| NOx 30 Day Achievable Emission Limit | 0.68 | - | 0.45 | - | 0.44 | - |
| NOx Annual Achievable Emission Limit | 0.63 | - | 0.41 | - | 0.40 | - |

* RSD = Relative Standard Deviation = 100 * Standard Deviation / Mean
Emissions are in lb/MBtu unless otherwise noted

Table 2. Baseline, LNCFS Level II and LNCFS Level III Long-Term Test Results.

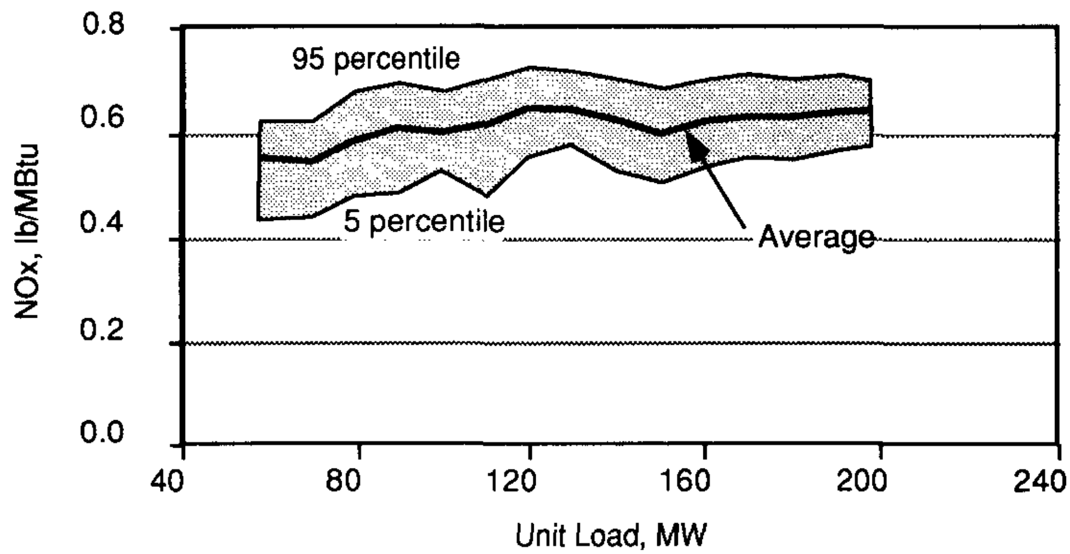



Fig. 4. Long-Term Baseline NOx Emissions.

In addition, the secondary air nozzles of a true LNCFS Level I system would provide a larger exit area. This difference in secondary air nozzle design is required to pass all of the secondary air through the main windbox with the appropriate design velocities for the furnace dimensions and the fuel being fired. The design of the Level I system at Plant Smith results in a higher velocity through the secondary air nozzles than a true Level I system. The effect of this Level I simulation with its associated higher mixing velocities may cause NOx emissions to be higher than normal and carbon loss to be lower than normal. The potential exists for the SOFA leakage effect of decreasing NOx emissions and the nozzle design effects of increasing NOx emissions to negate each other. Although a correction factor is being used to compensate for SOFA leakage, no attempt is being made to correct for the nozzle design effects on NOx emissions; therefore, a conservative approach is being used to estimate emissions with LNCFS Level I.

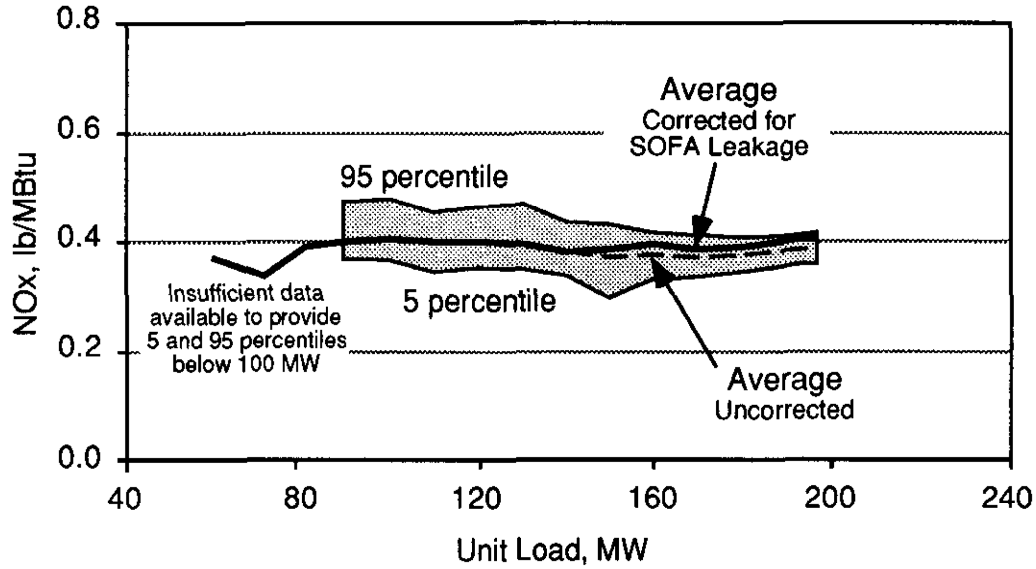



Fig. 5. Long-Term LNCFS Level I NOx Emissions.

Prior to testing, the LNCFS Level I system was optimized for performance and NOx emissions by engineers from ABB CE. Optimization of the system resulted in the CCOFA ports being positioned in line with the fuel nozzles. The position of the offset air nozzles was determined to be the same as the LNCFS Level III configuration (Table 3).

A portion of the LNCFS Level I diagnostic tests involved the characterization of the SOFA leakage effects on NOx emissions. These test showed that the leakage effects are only significant at full load. At minimum loads, the effect on NOx emissions is less than 0.1 percent. At full load, the leakage effects reduce unit NOx emissions by 4.6 percent. This effect is included in the presentation of the data.

LNCFS Level I testing began in April 1992 and is expected to be completed in September 1992. To date, 36 days of long-term data have been collected. Long-term NOx emissions over the entire load range are shown in Figure 5 and range from 0.40 lb/MBtu (full load) to 0.37 lb/MBtu (minimum load). The average, 5 percentile, and 95 percentile of the emissions data are shown. The percentile limits below 100 MW are not included in Figure 7 since a significant amount of data has not yet been collected in that load range. The average NOx emissions value is also shown after being corrected for leakage effects. This corrected curve is used for comparison to the other phases of the project.

## LNCFS Level II Test Summary

Prior to testing, the LNCFS Level II system was optimized for performance and NOx emissions by engineers from ABB CE. A portion of this process required the proper positioning of the three adjustable SOFA nozzles and the adjustable offset air nozzles in the main windbox. The optimized configuration for these nozzles with respect to the injection angle of the coal nozzles is shown in Table 4. The optimum tilt position for the SOFA nozzles was determined to be 0°. Tilt position for the main windbox varies to maintain unit reheat and superheat temperatures.

LNCFS Level II tests were completed in October 1991. A summary of the long-term test results is shown with the baseline results in Table 2. Fifty-five days of long-term data were collected generating an average emission level of 0.41 lb/MBtu. Long-term NOx emissions over the entire load range are shown in Figure 6 and range from 0.39 lb/MBtu (full load) to 0.57 lb/MBtu (minimum load). When operating with LNCFS Level II, NOx emissions varied by as much as 0.3 lb/MBtu at individual load values. The trend of increasing NOx emissions with decreases in load is consistent with previously reported data for low NOx combustion equipment on T-fired boilers [4].

## LNCFS Level III Test Summary

Prior to testing, the LNCFS Level III system was optimized for performance and NOx emissions by engineers from ABB CE. This process required the proper positioning of the three adjustable SOFA nozzles and the adjustable offset air nozzles in the main windbox. The final configuration

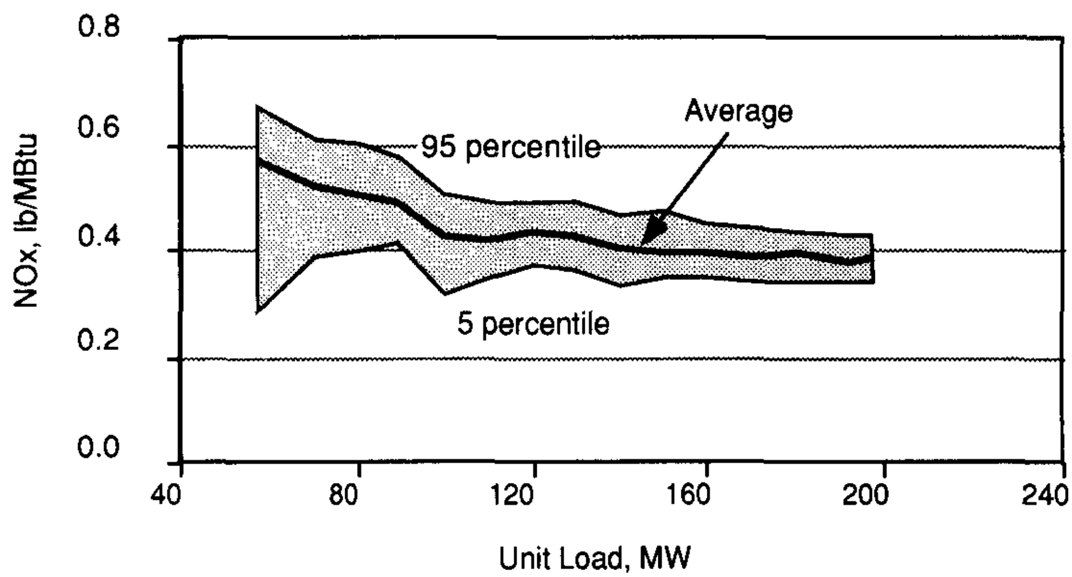



Fig. 6. Long-Term LNCFS Level II NOx Emissions.

| | Right Front | Right Rear | Left Front | Left Rear |
|---|---|---|---|---|
| SOFA Top | +12° | -12° | +12° | +12° |
| SOFA Middle | 0° | -12° | 0° | 0° |
| SOFA Lower | -12° | -12° | -12° | -12° |
| CCOFA Upper | 0° | 0° | 0° | 0° |
| CCOFA Lower | 0° | 0° | 0° | 0° |
| Offset Air | +16° | +16° | +16° | +16° |

Table 3: Optimized Orientation of SOFA (LNCFS III only) and Offset Air Nozzles with Respect to the Coal Nozzles for LNCFS Levels I and III (Positive Indicates Rotation with the Fireball).

| | Right Front | Right Rear | Left Front | Left Rear |
|---|---|---|---|---|
| SOFA Top | +15° | -15° | +15° | +15° |
| SOFA Middle | 0° | -15° | 0° | 0° |
| SOFA Lower | -15° | -15° | -15° | -15° |
| Offset Air | +22° | +22° | +22° | +22° |

Table 4: Optimized Orientation of SOFA and Offset Air Nozzles with Respect to the Coal Nozzles for LNCFS Level II (Positive Indicates Rotation with the Fireball).

for these nozzles with respect to the injection angle of the coal nozzles is shown in Table 3. The CCOFA nozzles are positioned in line with the coal nozzles.

LNCFS Level III testing began in November 1991 and was completed in March 1992. A summary of the long-term test results is shown with the baseline and LNCFS Level II results in Table 2. Seventy-one days of long-term data were collected generating an average emission level of 0.39 lb/MBtu. Long-term NOx emissions over the entire load range are shown in Figure 7 and range from 0.32 lb/MBtu (140 MW) to 0.60 lb/MBtu (minimum load). When operating with LNCFS Level III, NOx emissions varied by 0.3 lb/MBtu at minimum load values. However, the variations in emissions at full load were much less than the variations in the baseline or LNCFS Level II data.

Data Comparison

*NOx Emissions.* Figure 8 compares the averages of the baseline, LNCFS Level II, LNCFS Level III, and corrected LNCFS Level I long-term NOx emissions data. At full load, all three low NOx combustion technologies provide substantial NOx reductions over the baseline values. LNCFS Level I provides a maximum NOx reduction of 39 percent at 170 MW. LNCFS Level II provides a maximum NOx reduction of 40 percent at 190 MW. LNCFS Level III provides a maximum NOx reduction of 48 percent at 160 MW. At minimum load, NOx reduction is near zero percent for

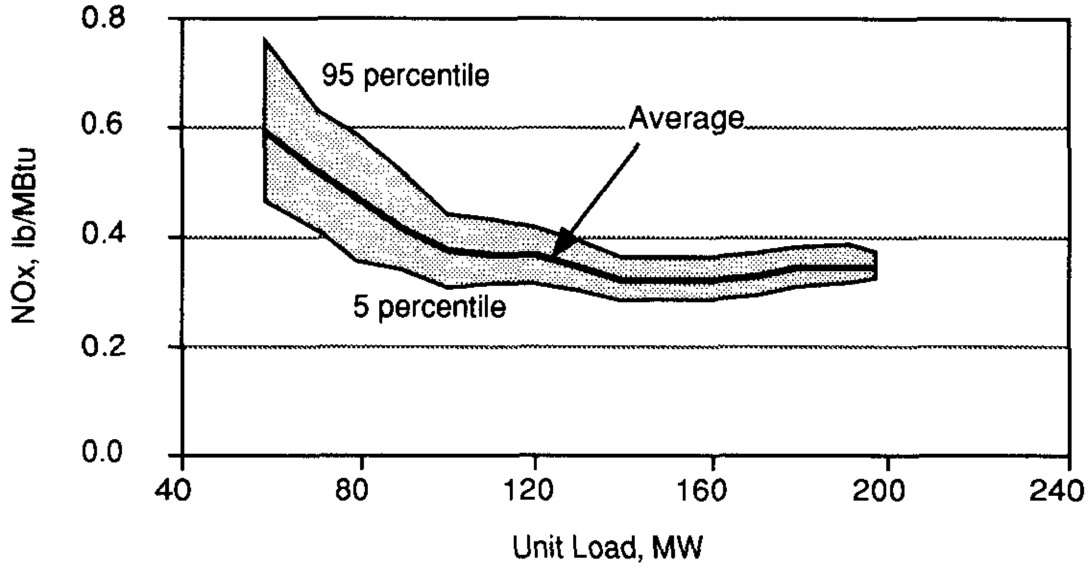



Fig. 7. Long-Term LNCFS Level III NOx Emissions.

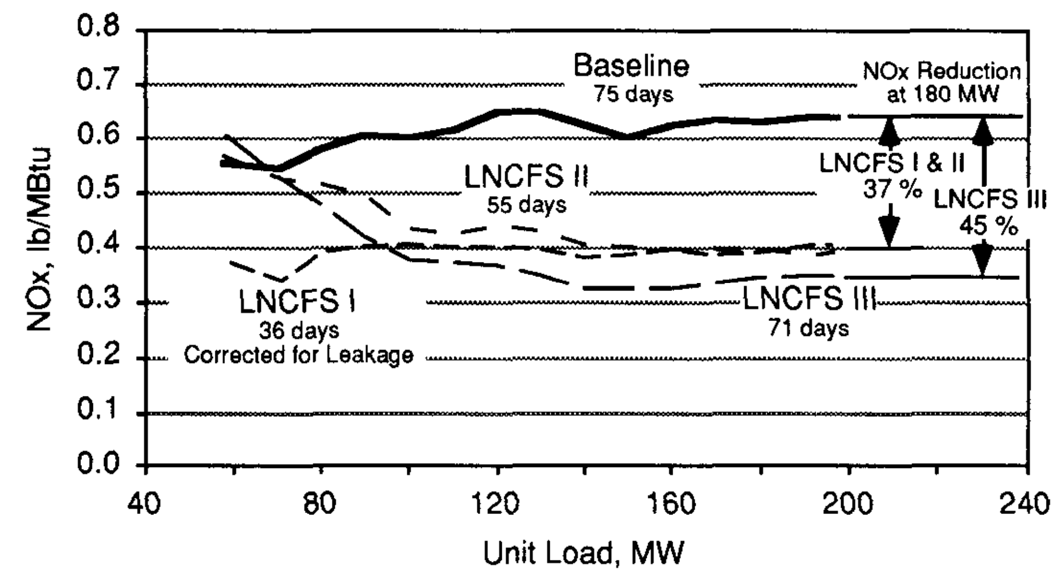



Fig. 8. Comparison of Average Long-Term NOx Emissions.

both LNCFS Level II and Level III. The shape of the NOx emissions profile for LNCFS Level I is similar to the shape of the baseline emissions curve.

*Excess Oxygen.* Short-term test results during all phases of the project have shown that excess oxygen level has a major impact on NOx emissions. As the excess oxygen level is decreased, NOx emissions also decrease. As a result, the capability to operate a low NOx combustion technology at lower excess oxygen levels increases its NOx emissions performance. At similar excess oxygen

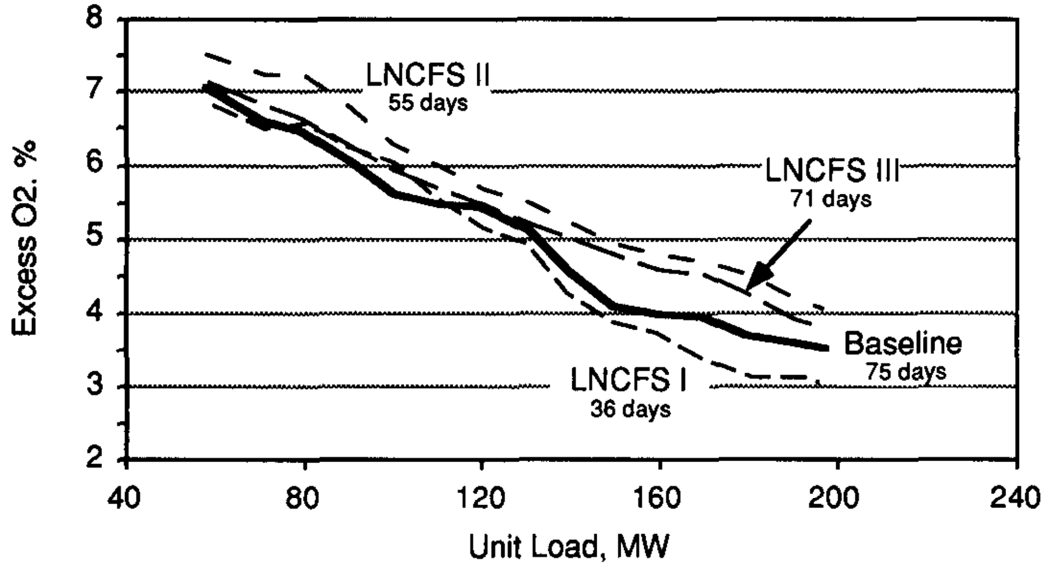



Fig. 9. Comparison of Average Long-Term Excess Oxygen Levels.

levels investigated during short-term tests, LNCFS Level II provided 5 percent greater NOx reductions than LNCFS Level I. However, LNCFS Level I can be operated at lower excess oxygen levels as described below. As a result, its long-term NOx reduction capability is similar to LNCFS Level II.

Figure 9 compares excess oxygen requirements for the technologies tested. These measurements were taken at the boiler economizer outlet using a multi-point grid of in-situ oxygen analyzers. During baseline operation, full load excess oxygen levels were near 3.5 percent. As load decreased, excess oxygen requirements increased to 7.0 percent at minimum load. Excess oxygen requirements for LNCFS Levels II and III were greater than the baseline levels. LNCFS Level II excess oxygen levels ranged from 4.0 percent at full load to 7.5 percent at low load. LNCFS Level III excess oxygen levels ranged from 3.8 percent to 7.1 percent. Excess oxygen requirements for LNCFS Level I were approximately 0.5 percent lower than baseline and 1.0 percent lower than LNCFS Level II at full load. As load decreased, LNCFS Level I excess oxygen requirements increased to near baseline levels.

During low load LNCFS Level II operations at Plant Smith, excess air levels were higher than full-load levels to maintain unit reheat and superheat temperatures (Fig. 9). Also the main coal and air nozzles were tilted upward to assist in maintaining steam temperatures. This mode of normal operation could have contributed to the increase in NOx emission at lower loads (Fig. 8). Another contributing factor to these increased NOx emissions is the variation in secondary air damper position settings among the technologies.

Following the long-term LNCFS Level II tests, ABB CE conducted a series of tests to determine if NOx emissions at lower loads could be reduced. The results indicated that increasing SOFA flows above ABB CE's previously optimized levels and reducing excess oxygen levels decrease low load NOx emissions to the full load values. These results have not been substantiated with long-term operation.

*Boiler Performance*. An important segment of the test program is to determine the impact of the low NOx combustion technologies on boiler performance. Boiler efficiency measurements are conducted as part of the performance tests and follow guidelines set forth in ASME PTC 4.1 [5]. As shown in Table 5, the installation of the low NOx combustion technologies has decreased full load boiler efficiency. However, in no cases to date has the efficiency been reduced by more than 0.5 percent. The LNCFS Level I efficiency data are not yet available.

*CO Emissions*. Figure 10 compares the CO emissions measured during each phase of long-term

| Phase | Efficiency (as measured) | Change from Baseline |
|---|---|---|
| Baseline | 90.11 | -- |
| LNCFS Level II | 89.77 | (0.34) |
| LNCFS Level III | 89.73 | (0.38) |

Table 5: Boiler Efficiencies at Full Load (180 MW).

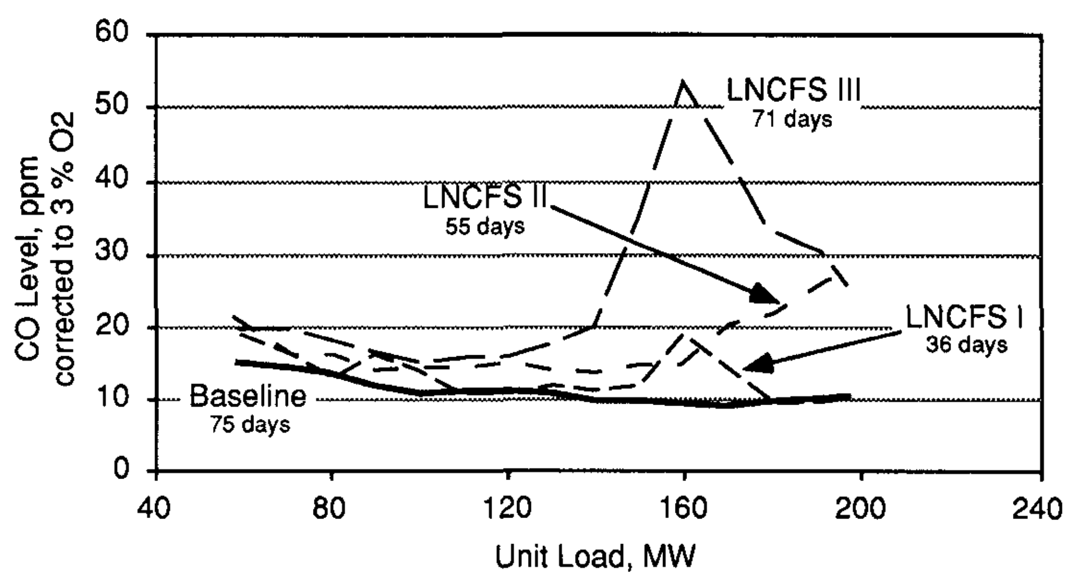



Fig. 10. Comparison of Average Long-Term CO Emissions.

testing. In a manner similar to the NOx emissions measurements, these values were taken at the stack with the ECEM and have been corrected to a 3 percent oxygen level. CO emissions during operation of LNCFS Level III were greater than baseline, LNCFS Level I, or Level II values. Maximum CO emissions with LNCFS Level III occurred at the same load value where the NOx reduction was greatest.

*Carbon Loss and Mill Performance.* Figure 11 compares the flyash loss-on-ignition (LOI) percentages measured during each set of performance tests. These measurements were made using EPA's Method 17 isokinetic sampling technique traversing multiple points at the economizer outlet of the boiler. LOI values for operation with LNCFS Level II are below those of baseline values for all load levels tested. Baseline tests were not conducted at 200 MW. LOI values with LNCFS Level I in operation were relatively consistent with the baseline values. LOI levels with LNCFS Level III were greater than baseline levels.

Mill performance levels during each set of tests are shown in Table 6. Fuel fineness was measured using an isokinetic sampler at the exhauster outlet of each mill. The isokinetic sampling method has consistently resulted in lower fineness results than ABB CE's recommended method for collecting fuel samples. While the ABB CE procedure is not an isokinetic sampling method, it is widely recognized as the standard for the collection of fuel samples on CE mills. Where available data from both testing methods are shown.

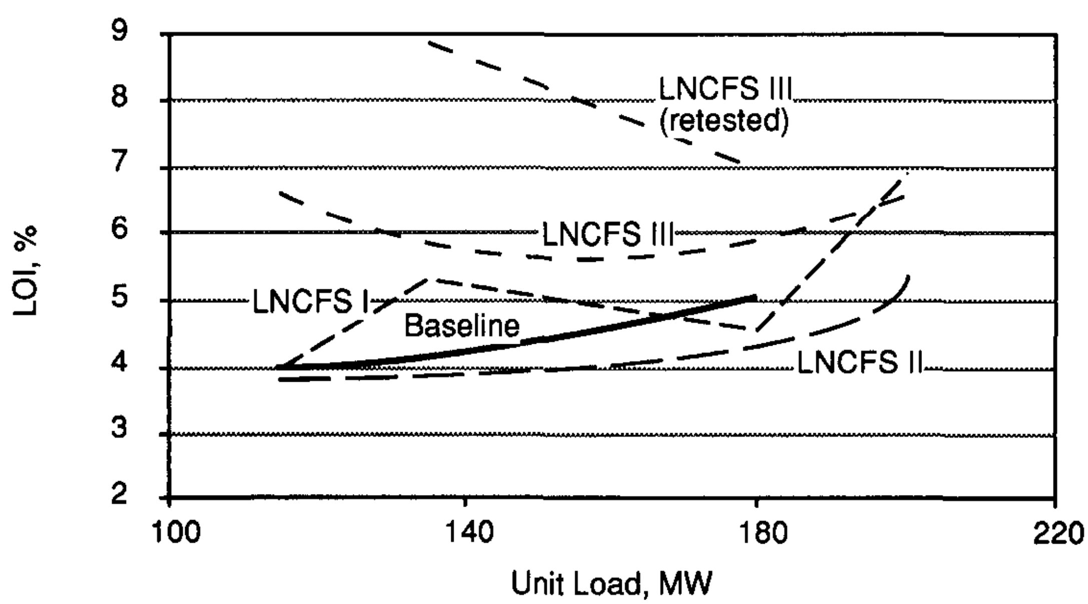



Fig. 11. Comparison of Flyash LOI (Carbon Carryover) Values.

| | Percent Left on 50 Mesh | | Percent Passing 200 Mesh | |
|---|---|---|---|---|
| | Isokinetic Method * | ABB CE recom method ‡ | Isokinetic Method * | ABB CE recom method ‡ |
| Baseline | 2.6 | 2.4 | 58.9 | 68.6 |
| LNCFS Level II | 2.0 | n/a | 62.9 | n/a |
| LNCFS Level III | 3.2 | 1.3 | 55.7 | 75.3 |
| LNCFS Level I | 2.9 | 1.1 | 55.4 | 71.6 |
| LNCFS Level III (retest) | 2.5 | 1.1 | 55.5 | 71.6 |

* Mill Coal Flow Weighted Average ‡ Simple Average

Table 6: Mill Performance at Full Load (180 MW) Based on Two Different Flyash Sampling Techniques at the Exhauster Outlet.

Due to concern over the higher LOI values with LNCFS Level III, additional LOI tests were conducted in May 1992. These results, shown in Figure 11 and labeled "LNCFS III (retested)," confirmed that LOI values are higher with LNCFS Level III.

Unit Operations

In the baseline configuration of the boiler, the coal and air nozzles were fixed in the horizontal position since the tilting mechanisms were inoperable. During the outage to install LNCFS Level II, the burner tilting system was completely replaced. As a result, unit operators reported that the tilt mechanisms allowed better control of reheat and superheat temperatures with all three levels of the LNCFS.

Other than the tilt improvements, unit operations with LNCFS Level I were reported to be similar to baseline conditions. Fireball rotation, furnace clarity (visibility), flame brightness, and flexibility in unit operations did not change appreciably from the baseline condition. Unit operations with LNCFS Level II were also reported to provide the flexibility in operations of the baseline configuration. With LNCFS Levels II and III operation, fireball rotation rate slowed, furnace clarity decreased, and flame brightness dimmed. The redirection of secondary air to the SOFA nozzles is the primary reason for the change in fireball rotation rate and the furnace brightness. The extended combustion zone created by the overfire air process resulted in lower furnace gas clarity. With operation of all three levels of LNCFS, there was no increased loading on the precipitator; however, the predominant slagging location moved from the combustion zone of the furnace to the convection pass.

Although there were no effects on unit availability, boiler operation with LNCFS Level III was characterized as more difficult than the baseline, Level I, or Level II configurations. Load transitions that require bringing mills into and out of service generally resulted in spikes of CO and NOx emissions. Flexibility in unit operations with respect to the range of excess oxygen levels available for operation was more restricted. This characteristic is reflected in the tight band of NOx emissions generated at each load during LNCFS Level III operation (Fig. 7). Slagging patterns and precipitator loadings with LNCFS Level III were similar to those experienced with Level II.

## CONCLUSIONS

All three levels of ABB CE's Low NOx Concentric Firing System have been successfully demonstrated at Gulf Power Company's 180 MW Plant Lansing Smith Unit 2. With LNCFS Levels I and II in operation, NOx emissions were reduced by as much as 40 percent with no increases in flyash carbon content. With LNCFS Level III in operation, NOx emissions were reduced by as much as 48 percent; however, flyash carbon content increased by 50 percent (at full load.) All three levels of the LNCFS reduced full-load NOx emissions below the presumptive 0.45 lb/MBtu standard for T-fired boilers. No major operational or equipment problems were encountered with any of the three systems tested.


## ACKNOWLEDGMENTS

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# DEMONSTRATION OF SELECTIVE CATALYTIC REDUCTION (SCR) TECHNOLOGY FOR THE CONTROL OF NITROGEN OXIDE ($NO_x$) EMISSIONS FROM HIGH-SULFUR, COAL-FIRED BOILERS

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**Abstract**

This paper describes the status of the Innovative Clean Coal Technology project to demonstrate SCR technology for reduction of $NO_x$ emissions from flue gas of utility boilers burning U. S. high-sulfur coal. The funding participants are the U. S. Department of Energy (DOE), Southern Company Services, Inc. (SCS, on behalf of the entire Southern Company), and the Electric Power Research Institute (EPRI). SCS is the participant responsible for managing all aspects of the project. The project is being conducted on Gulf Power Company's Plant Crist Unit 5 (75-MW capacity), located near Pensacola, Florida, on U. S. coals that have a sulfur content near 3.0%. The SCR facility will treat a 17,400 scfm slip-stream of flue gas and consists of three 2.5-MW (5000 scfm) and six 0.2-MW (400 scfm) SCR reactors. The reactors will operate in parallel for side-by-side comparisons of commercially available SCR catalyst technologies obtained from vendors throughout the world. The majority of detailed design engineering is complete. Construction is scheduled to be completed at the end of December 1992. After a start-up/shakedown period, long-term performance testing will be conducted for two years. Design issues and the project construction status are reported in this paper.

DEMONSTRATION OF SELECTIVE CATALYTIC REDUCTION (SCR) TECHNOLOGY FOR THE CONTROL OF NITROGEN OXIDE ($NO_x$) EMISSIONS FROM HIGH-SULFUR, COAL-FIRED BOILERS

## BACKGROUND

The first four solicitations of the U. S. Department of Energy's (DOE's) Innovative Clean Coal Technology (ICCT) Program are designed to demonstrate clean coal technologies that are capable of retrofitting or repowering existing facilities to achieve significant reduction in sulfur dioxide ($SO_2$) and/or nitrogen oxides ($NO_x$) emissions. The technologies selected for demonstration are capable of being commercialized in the 1990s and are expected to be more cost effective than current technologies.

In 1988, in response to the second ICCT solicitation, Southern Company Services (SCS), Inc., on behalf of the Southern electric system, submitted proposals, and was awarded four Innovative Clean Coal Technology projects. Funding for the projects is being provided by the operating utilities of The Southern Company, DOE, and the Electric Power Research Institute. One project seeks to demonstrate significant cost savings to the Chiyoda Thoroughbred-121 (CT-121) flue gas desulfurization (FGD) process and consists of constructing and operating a 100-MW scrubber at Georgia Power's Plant Yates. Two other projects focus on full-scale demonstration of seven advanced combustion techniques for reduction of nitrogen oxides ($NO_x$). One of the two low $NO_x$ combustion projects is a demonstration of low-$NO_x$ burners (LNB) and advanced over-fire air (AOFA) on a 500-MW, pulverized coal, wall-fired unit at Georgia Power's Plant Hammond. The second low $NO_x$ combustion project is demonstrating various low-$NO_x$ combustion techniques for pulverized coal, corner-fired boilers. This demonstration is being conducted at Gulf Power's Plant Smith on a 180-MW unit.

The fourth project (and subject of this paper) is a demonstration of selective catalytic $NO_x$ reduction (SCR) on an 8.7-MW slip-stream from one unit at Gulf Power's Plant Crist. The performance of this project recognizes that combustion modifications alone might not be sufficient to comply with proposed $NO_x$ emissions limits. These four projects are part of an integrated strategy by the Southern electric system to demonstrate lower cost, retrofit emission control options for sulfur dioxide and nitrogen oxides.

**SCR Technology Overview and Development Status**

This ICCT project is being managed by SCS, and its objective is to demonstrate the SCR process for removing $NO_x$ from the flue gas of boilers that burn U. S. high-sulfur coal. The SCR technology involves the injection of ammonia into the flue gas that passess through a catalyst bed where $NO_x$ and ammonia react to form harmless nitrogen and water vapor.

A simplified, typical SCR process installation for a utility boiler is depicted with major equipment in Figure 1. Hot flue gas leaving the economizer section of the boiler is ducted to the SCR reactor. Prior to entering the reactor, ammonia ($NH_3$) is injected into the flue gas at a sufficient distance upstream of the SCR reactor to provide for complete mixing of the $NH_3$ and flue gas. The quantity of $NH_3$ can be adjusted for the desired degree of reaction with the $NO_x$ from the flue gas as the gases pass through the catalytic bed of the reactor. The flue gas leaving the reactor enters the air preheater where it transfers heat to the incoming combustion air. Provisions are made for ash removal from the bottom of the reactor since some fallout of fly ash is expected. Ductwork is also installed to bypass some flue gas around the economizer during periods when the boiler is operating at reduced load. This is done, especially on retrofits, to maintain the temperature of the flue gas entering the catalytic reactor at the proper reaction temperature of about 700°F. The flue gas that exits the air preheater continues on to the boiler's particulate removal device.

SCR technology is in commercial use in Japan and Western Europe on gas-, oil-, and low-sulfur, coal-fired power plants. The first utility applications of SCR catalyst technology started in Japan in 1977 for oil- and gas-fired boilers and subsequently in 1980 for coal-fired boilers. There are now over 36,000 MW of fossil-fuel-fired SCR capacity in Japan, including 6,200 MW on coal. Several countries in Western Europe (most notably Germany and Austria) have passed stringent $NO_x$ emission regulations that have essentially mandated the installation of SCR. There are over 33,000 MW of fossil-fuel-fired SCR capacity in Western Europe, including 30,500 MW of coal-fired capacity .

**SCR Demonstration Goals**

Although SCR is widely practiced in Japan and Western Europe, numerous technical uncertainties are associated with applying SCR to U. S. coals. These uncertainties include:

(1) potential catalyst deactivation due to poisoning by trace metal species present in U. S. coals that are not present or present at much lower concentrations in other fuels.

(2) performance of the technology and effects on the balance-of-plant equipment in the presence of high amounts of $SO_2$ and $SO_3$ (e.g., plugging of downstream equipment with ammonia-sulfur compounds).

(3) performance of a wide variety of SCR catalyst compositions, geometries and manufacturing methods for typical high-sulfur coal-fired utility operating conditions.

These uncertainties will be explored by constructing a series of small-scale SCR reactors and simultaneously exposing different SCR catalysts to flue gas derived from the combustion of high sulfur U. S. coal.

The first uncertainty will be handled by evaluating SCR catalyst performance for two years under realistic operating conditions found in U. S. pulverized-coal utility boilers. Deactivation rates for the catalysts exposed to flue gas of high sulfur U. S. coal will be documented to determine catalyst life and associated process economics.

The second uncertainty will be explored by performing parametric tests with the installation/operation of air preheaters downstream of the larger SCR reactors. During the parametric tests, SCR operating conditions will be adjusted above and below design values to observe $deNO_x$ performance and ammonia slip (leakage of unreacted ammonia through the SCR reactor) as functions of the change in operating conditions. Air preheater performance will be observed to evaluate the effects of SCR operating conditions upon heat transfer and boiler efficiency.

The third uncertainty is being addressed by using honeycomb- and plate-type SCR catalysts of various commercial composition from U. S., Japan, and Europe. Results from the tests with these catalysts will expand the knowledge of performance on a variety of SCR catalysts under U. S. utility operating conditions with high-sulfur coal.

The intent of this project is to demonstrate commercial catalyst performance, and determine proper operating conditions and catalyst life for the SCR process. This project will also demonstrate the technical and economic viability of SCR while reducing $NO_x$ emissions by at least 80%.

**SCR Demonstration Facility Description**

The SCR demonstration facility is located at Gulf Power Company's Plant Crist in Pensacola, Florida. The facility will treat a flue gas slip-stream from Unit 5, a commercially operating 75-MW unit, firing U. S. coals with a sulfur content near 3.0%. Unit 5 is a tangentially-fired, dry bottom boiler with hot and cold side electrostatic precipitators (ESPs) for particulate control. The SCR test facility consists of nine reactors operating in parallel for side-by-side comparisons of commercially available SCR catalyst technologies obtained from vendors throughout the world. With all reactors in operation, the amount of combustion flue gas that can be treated is 17,400 standard cubic feet per minute (scfm) which is roughly equivalent to 8.7 MWe (or 12% of Unit 5's capacity). This demonstration facility size will be adequate to develop performance data to evaluate SCR capabilities and costs that are applicable to boilers using high-sulfur U. S. coals.

The process flow diagram for the SCR test facility is shown in Figure 2. There are three large SCR reactors (2.5 MW, 5000 scfm) and six smaller SCR reactors (0.2 MW, 400 scfm). High-dust flue gas is extracted from the inlet duct of the hot-side ESP. The high-dust flue gas is distributed to the three large reactors and five of the small reactors. One small reactor is operated with low dust extracted from the hot-side ESP outlet duct. Eight of the nine reactors will operate with flue gas containing full particulate loading (high dust) while one reactor will use flue gas fed from the ESP outlet (low dust). This will provide experience with alternative SCR application scenarios which are possible within typical power plants.

Each reactor train has electric duct heaters to control the temperature of the flue gas and a venturi flow meter to measure the flue gas flow to the reactors. Anhydrous ammonia is independently metered to a stream of dilution air that injects the ammonia via nozzles into the flue gas stream prior to each SCR reactor. An economizer bypass line to the SCR pilot plant maintains a minimum flue gas temperature of 620°F supplied to the pilot plant.

The flue gas and ammonia pass through the SCR reactors, which have the capacity to contain up to four catalyst layers. There is a flow straightening grid (i.e., dummy layer) at the top of each SCR reactor to prevent swirling of the flue gas which could cause erosion problems when catalysts are operated under high-dust conditions.

For the large reactor trains, the flue gas exits the reactor and enters a pilot-scale air preheater (APH). The APHs are incorporated to evaluate the effects of SCR reaction chemistry on APH deposit formation and the effects from the deposits on the APH performance and operations. The small reactors do not have APHs following the SCR reactors. All reactor trains, except the low-dust train, have a cyclone downstream of the SCR reactors to protect the induced draft (ID) fans from particulates. The small reactors are grouped into three reactors per ID fan.

The exhaust for all the SCR reactors is combined into a single manifold and routed back to the host boiler for reinjection ahead of the cold-side ESP. The preheated air from the APH on the large reactors is also combined into a single manifold and returned to the host boiler draft system at the air outlet of the existing APH. All of the particulates that are removed from the flue gas with the cyclones are combined and sent to an ash disposal area.

Each of the large reactor trains have individual bypasses to facilitate start-up/shutdown and operation of the test facility. Flue gas can be directed through the large reactor bypass to the APH or a bypass heat exchanger. The APH will be bypassed during parametric testing so that ammonia-to-$NO_x$ values higher than design will not effect long-term deposit formation in the APH due to excessive ammonium bisulfate formation.

**Catalyst Testing Plans**

Seven catalyst suppliers are participating in this project, supplying nine different catalysts. Two suppliers are from Europe, two are from Japan, and three are U. S. firms. The catalysts being evaluated represent the wide variety of SCR catalysts being offered commercially and possess different chemical compositions and physical shapes. Of these nine catalysts, six have a honeycomb geometry while the remaining three are plate-type catalysts. The suppliers, applicable reactor size, and catalyst configuration are listed in Table 1.

The deactivation rates of commercially available SCR catalysts being exposed to flue gas from high-sulfur U. S. coals will be determined by evaluating catalyst $deNO_x$ efficiency and other performance variables as a function of three main process variables: ammonia-to-$NO_x$ ratio, temperature, and space velocity. (Space velocity is the ratio of flue gas volumetric flow rate to catalyst volume. With a fixed catalyst volume, variations in flue gas flow rates will alter the space velocity around the design point.)

After start-up, the baseline performance of each catalyst will be determined at design conditions. Once baseline conditions have been established, each catalyst will be sequenced through a test matrix that varies each of the above variables around the design point. Appropriate $deNO_x$ efficiency, pressure drop, $SO_2$ oxidation, and ammonia slip will be determined at each test condition. Once the initial parametric test matrix has been completed, each reactor will be returned to baseline design conditions, allowing for steady-state operation over a three month period, for aging of the catalyst. The parametric test matrix will be repeated every three months for each reactor train. Only one reactor train will be undergoing parametric testing at any one time. The remaining reactors will be either in steady-state operation or off-line.

The operating parameter ranges to be examined during the parametric tests and the long-term design condition (baseline) are as follows:

| | Minimum | Baseline | Maximum |
|---|---|---|---|
| Temperature, °F | 620 | 700 | 750 |
| $NH_3/NO_x$ molar ratio | 0.6 | 0.8 | 1.1 |
| Space velocity, | | | |
| • % of design flow | 60 | 100 | 150 |
| • Flow rate, scfm | | | |
| - large reactor | 3000 | 5000 | 7500 |
| - small reactors | 240 | 400 | 600 |

When each parametric test is conducted, a catalyst sample will be taken and submitted to the catalyst supplier for laboratory analyses. Common laboratory testing protocol has been established with the catalyst vendors.

**Project Schedule, Design, and Construction Status**

The demonstration project is organized into three phases. Phase I consists of permitting, preparing the Environmental Monitoring Plan and preliminary engineering; this has been completed. Phase II includes detail design engineering, construction, and start-up/shakedown. Detail design engineering began in early 1991 and is continuing with about 90% of the work completed. Major subsystems (including the air preheaters, gas/air fans, venturis, distributed control/data acquisition, electrical, bypass heat exchangers, cyclones, flue gas/air electric heaters, gas analysis, and ammonia storage) have been specified, ordered, and most equipment has been delivered. Construction began at the end of March 1992 and is scheduled to be completed at the end of 1992. As of early August, foundations were complete and a majority of the structural steel was erected. Installation of some of the equipment (fans, service air and water systems, and electrical systems) has commenced. All of the major construction contracts have been awarded. Start-up/shakedown should occur during the first quarter of 1993. Phase III is the operations phase for process evaluation. The process evaluation will last for two years, through March 1995, and will be followed by preparation of a final report, which will include process economic projections. The major milestones remaining on the project schedule are shown in Table 2.

**Design Issues**

Some of the lessons learned during the design of this facility include the following items:

Reactor Inlet Ducting/ Ammonia Injection Grid-- For the reactor inlet ducting design, DynaGen, Inc. performed flow modeling tests with a 1/2 scale model of the inlet ducting for two alternative designs. Each alternative reflected the following changes from the original reactor inlet concept which was a vertical downflow reactor inlet with expansion into the reactor in two dimensions: a) change from a vertical inlet duct run to a horizontal duct run with round to rectangular duct transition; b) addition of a diffuser, equipped with internal baffle plates and expansion in only one dimension; and c) transition from horizontal to vertical flow into the reactor inlet is equipped with turning vanes.

The model design achieving the best velocity uniformity results and requiring the minimum space is shown in Figure 3, along with the testing arrangements. This design incorporated the remaining expansion in the horizontal to vertical flow transition. The velocity profile data for the inlet geometry in the round piping ductwork (location 1) is shown in Figure 4 to be uniform and symmetric. However, in initial flow model testing, the velocity profile uniformity at location 2, which is the diffuser outlet, was much less uniform than at location 1 with high velocities, about 50 percent above average, in the center, and low velocities at the walls, as shown in Figure 5. This phenomena resulted from the flow area expansion from a one foot circle to a one foot square, followed by the expansion across the diffuser to a 1.5 foot x 2 foot cross-section.

To reduce the velocities and distribute the flow more uniformly, a set of resistance pipes was located immediately at the outlet of the circle to square transition (which also corresponds to a possible ammonia injection cross-section). Slight modifications in detail geometry of the resistance pipes progressively improved the velocity uniformity at location 2, the diffuser outlet. Uniformity went from 16.7 percent of the data within +/- 10 percent, (without resistance pipes) as depicted in Figure 5, to 87.5 percent of data within +/- 10 percent as shown in Figure 6 for the final resistance pipe design selected. This design selection is shown in Figure 7.

A graphical display of the poorer velocity uniformity at location 4 (dummy layer outlet) for the design without resistance pipes is presented in Figure 8. In comparison, the velocity profile results at location 4 for the optimum design tested are shown in Figure 9. Table 3 summarizes the results at locations 2 and 4 for the optimum design. About 96 percent of the results were within +/- 10 percent of the average velocity and 99 percent of the results were within +/- 15 percent of the average for the selected optimum design.

One change, subsequently incorporated from the figures shown, is an increase from a four-cell diffuser with three baffles, to a five cell diffuser with four baffles. This will be a better match for a 5x5 nozzle array for ammonia injection.

Economizer Bypass-- The development experience of some SCR vendors indicates that catalyst activity loss may vary with the extraction location of the flue gas from the host boiler. Flue gas extracted and treated immediately at the economizer wall can show higher trace metal concentrations and can lead to higher catalyst poisoning. Extracting and treating flue gas, after long duct runs with cooler gas temperatures, may allow vapor phase metal condensation. If extracted in this manner for a pilot plant, the catalyst possibly may not get exposed to the actual trace metal concentration that the catalyst would see on a commercial system.

The vapor phase trace metal concentration in the flue gas may decrease as a result of (1) temperature drop between the boiler-economizer outlet and extraction scoop and between the scoop and heater or pilot SCR reactor; (2) flue gas residence time in the duct; and (3) heater surface temperature. A change in this vapor phase metal concentration may result in different, possibly improved, catalyst deactivation rates than would normally be achieved on a full-scale facility. As a result, in addition to thicker insulation for the inlet ductwork to the reactor, the project scope has been increased to include an economizer bypass.

The temperature of the flue gas being extracted and sent to the distribution header for the SCR reactors will be monitored. This measurement will be used to control a flow control damper on the economizer bypass line to maintain a minimum temperature of 620° F for the flue gas entering the test facility. As the boiler load decreases from full load and the temperature of the extracted flue gas decreases below 620° F, the damper will open, allowing hotter flue gas from above the boiler-economizer region to mix with and raise the temperature of the flue gas entering the SCR system. Trace metal vapor phase condensation is minimized, and the catalyst is exposed to levels of potential poisons similar to those expected in a commercial system.

Electric Flue Gas Heaters and Air Purge-- The flue gas electric heaters will be used to control the temperature of the flue gas entering each SCR reactor. Each reactor train will utilize an independently operated heater, or bank of heaters, to control the flue gas temperature for that particular reactor. The flue gas temperature coming out of the electric heaters will range from 620°F with heaters out of service to 750°F with maximum heater operation.

The flue gas electric heaters will also provide a heat source to heat ambient air when purging the reactor of combustion gases or heating the reactor up during cold start-ups.

The ambient air purge allows controlled startup and shutdown of the catalyst, particularly when passing through moisture and acid dewpoints. The flue gas electric heaters will be required to heat ambient air from a temperature of 30°F to 300°F when operating at the minimum reactor flowrate, 3000-scfm for large reactors, and 240-scfm for small reactors.

Ammonia Dilution Air Supply and Electric Heaters-- Ammonia is stored as an anhydrous liquid, vaporized and diluted with air prior to injection into the flue gas upstream. The dilution accomplishes two purposes: First, it produces a gaseous mixture outside the flammability limits and it also increases the volume of injected gas for improved flow control and mixing with the flue gas.

The ammonia dilution air utilizes a common centrifugal fan with a common dilution air heater to furnish heated dilution air for all reactors. The heater will utilize a silicon control rectifier, to adjust heater power output with any combination of reactors in or out of service.

The ammonia dilution air heater will be used to heat the ambient dilution air to approximately 500°F, to minimize formation of ammonium bisulfate (ABS) and plugging of the ammonia injection nozzles. By raising the temperature of the dilution air this high, the temperature of the air is also raised above the acid dew point, which minimizes corrosion. The ammonia dilution air heaters will be required to heat ambient air from a temperature of 30°F to 500°F. This will also aid in reducing erroneous $NH_3/NO_x$ measurements caused by loss of ammonia through condensation of ABS.

Flyash Buildup on Catalyst and Sootblowing-- Flyash buildup on the reactor walls and the catalyst surface is a concern for the pilot scale reactors. Previous pilot plant experience by others suggests that flyash deposition is due to small recirculation zones at the entrance and exit of the catalyst modules. SCS intends to minimize the recirculation zones, and hence the flyash buildup on the catalyst modules, by minimizing the distance that the catalyst support structure protrudes into the gas path of the reactor.

The reactor design also allows approximately 5 to 6 feet between catalyst modules to allow flow patterns to become more streamlined before entering the next catalyst module. The plate-type catalyst may experience less ash deposition problems due to its typically greater void volumes. A wire mesh screen cover will be placed over the catalyst surface to catch large ash particles, preventing them from lodging on the catalyst surface and physically blocking channels.

In addition to the above-mentioned items, each reactor will have provisions for sootblowing on each catalyst layer and the dummy layer. The large reactors will use a traversing-type, retractable sootblower to deliver superheated steam from the Unit 5 boiler to the surface of the catalyst. The small reactor sootblower will utilize air from the service air system and be stroked manually across catalyst layers by plant personnel. Sootblowing will be sequenced from the top to the bottom of the reactors and controlled by the pilot plant control system.

## Summary

The need within the utility industry for detailed information on SCR technology has never been greater. The 1990 Clean Air Act Amendments (CAAA) create two new potential $NO_x$ control requirements on fossil fuel-fired utility boilers. Title IV of the CAAA regarding acid rain requires emission limits be placed on all coal-fired utility boilers in two phases - one beginning in 1995 and the other in the year 2000. Although low $NO_x$ burner technology is receiving the most prominent mention in meeting the Title IV provisions, the final EPA emission limitations for each of the two phases remain to be established, and SCR is still very much considered in utilities' compliance strategies. Title I of the CAAA addresses attainment of the ambient air quality standards. Regarding ozone, Title I calls for certain areas presently not in attainment to consider $NO_x$ controls to achieve attainment. As a result, renewed focus has been placed on $NO_x$ controls, including advanced $NO_x$ control technology such as SCR, which may be required to meet compliance requirements for ozone non-attainment areas.

During this ICCT demonstration, performance data will be developed to evaluate SCR capabilities and costs that are applicable to boilers using high-sulfur U. S. coals. The SCR demonstration facility design is essentially complete and construction is underway. Start-up should commence early next year followed by a two-year process evaluation, which will be completed in 1995.

TABLE 1

SCR PROJECT CATALYST SUPPLIERS

| Catalyst Vendor | Reactor Size | Catalyst Configuration |
|---|---|---|
| Nippon Shokubai | Large | Honeycomb |
| Siemens AG | Large | Plate |
| W. R. Grace | Large | Honeycomb |
| Engelhard | Small | Honeycomb (low dust) |
| Engelhard | Small | Honeycomb (high dust) |
| Haldor Topsoe | Small | Plate |
| Hitachi Zosen | Small | Plate |
| W. R. Grace | Small | Honeycomb |
| To be determined | Small | To be determined |

TABLE 2

PROJECT SCHEDULE

| | |
|---|---|
| Detailed Engineering | 1/92 - 1/93 |
| Construction | 3/92 - 12/92 |
| Start-up/Shakedown | 1/93 - 3/93 |
| Process Evaluation | 4/93 - 3/95 |
| Disposition/Final Report | 4/95 - 7/95 |

TABLE 3

VELOCITY PROFILE TEST RESULTS SUMMARY
FOR SELECTED MODEL REACTOR INLET DESIGN

| Geometry Description | Location No.- Description | RMS[a] | +/- 10% band,[b] (%) | +/- 15% band,[c] (%) |
|---|---|---|---|---|
| Open design with elbow and diffuser vanes/ No spacer between elbow and core/ | 2 - Diffuser outlet | 0.066 | 87.5 | 97.9 |
| Five 1" dowels unequally spaced, 58.3% open average | 4 - Dummy layer outlet | 0.049 | 95.5 | 99.0 |

a) RMS = Standard deviation of velocity about an average velocity, expressed as a fraction of the average velocity. For a value of zero, the flow would be perfectly uniform with all data points equal.

b) Percentage of data within +/- 10% band about the average.

c) Percentage of data within +/- 15% band about the average.

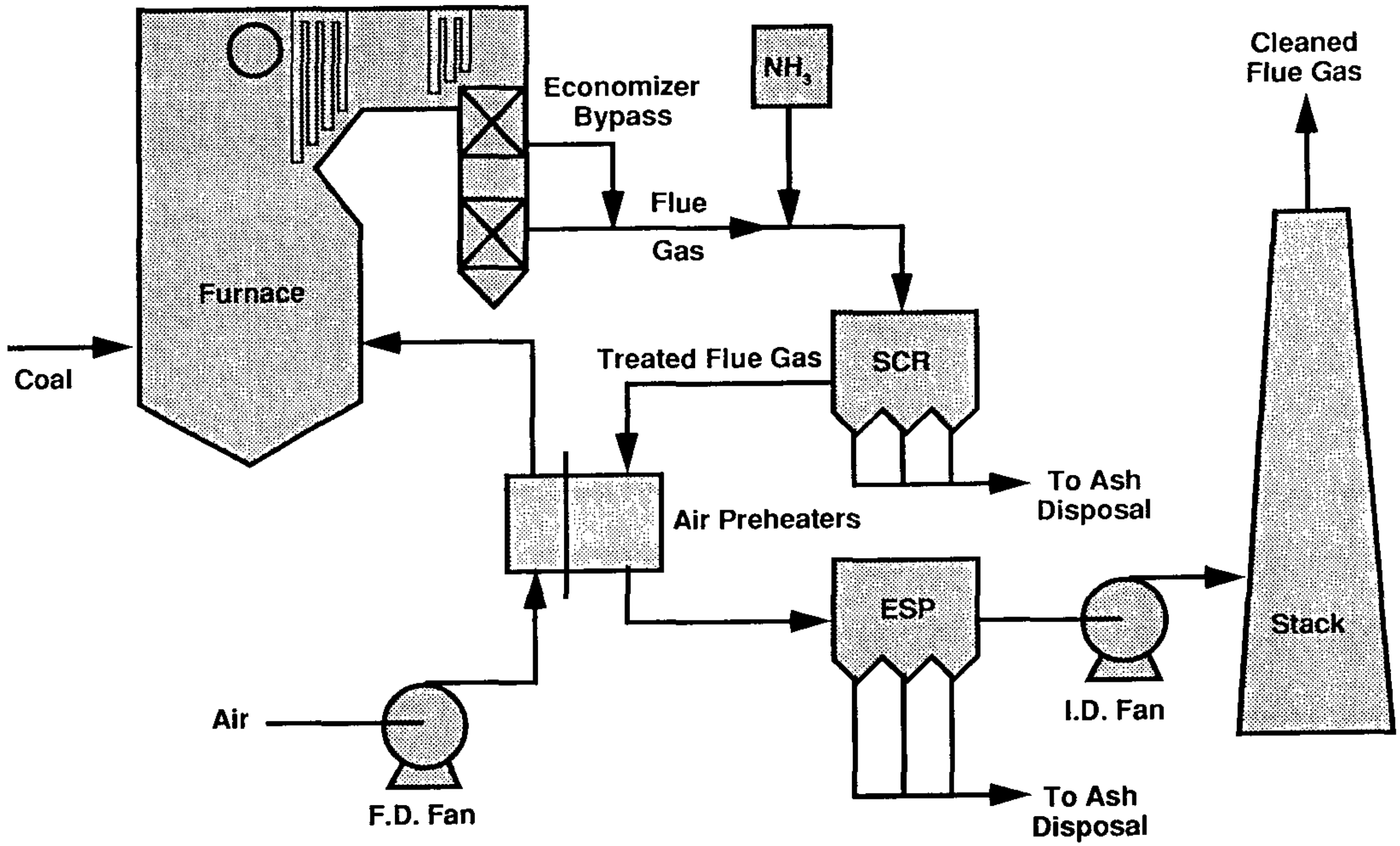


**Figure 1. *Flow Diagram of a Typical SCR Installation.***

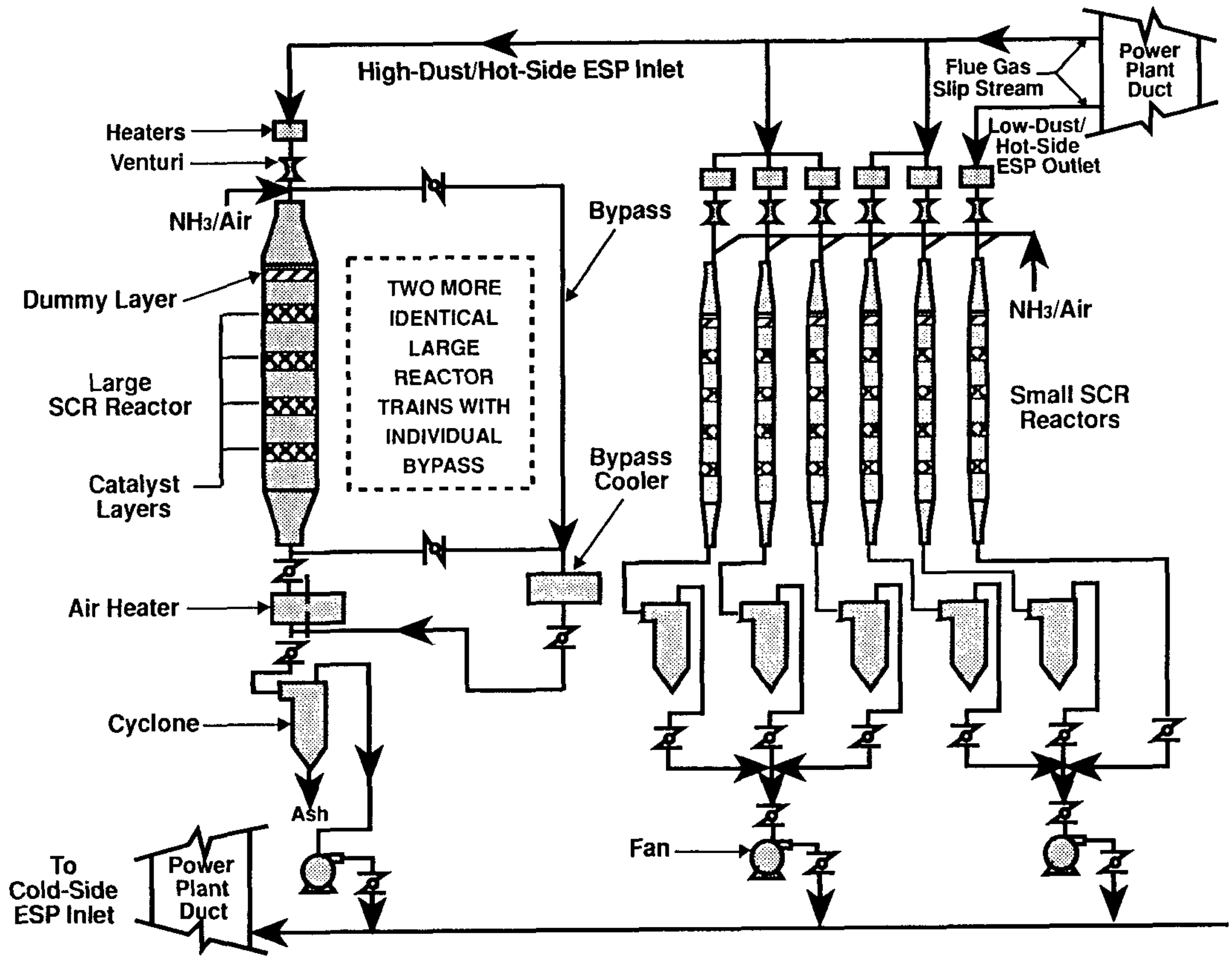


Figure 2. Prototype SCR Demonstration Facility-Process Flow Diagram.

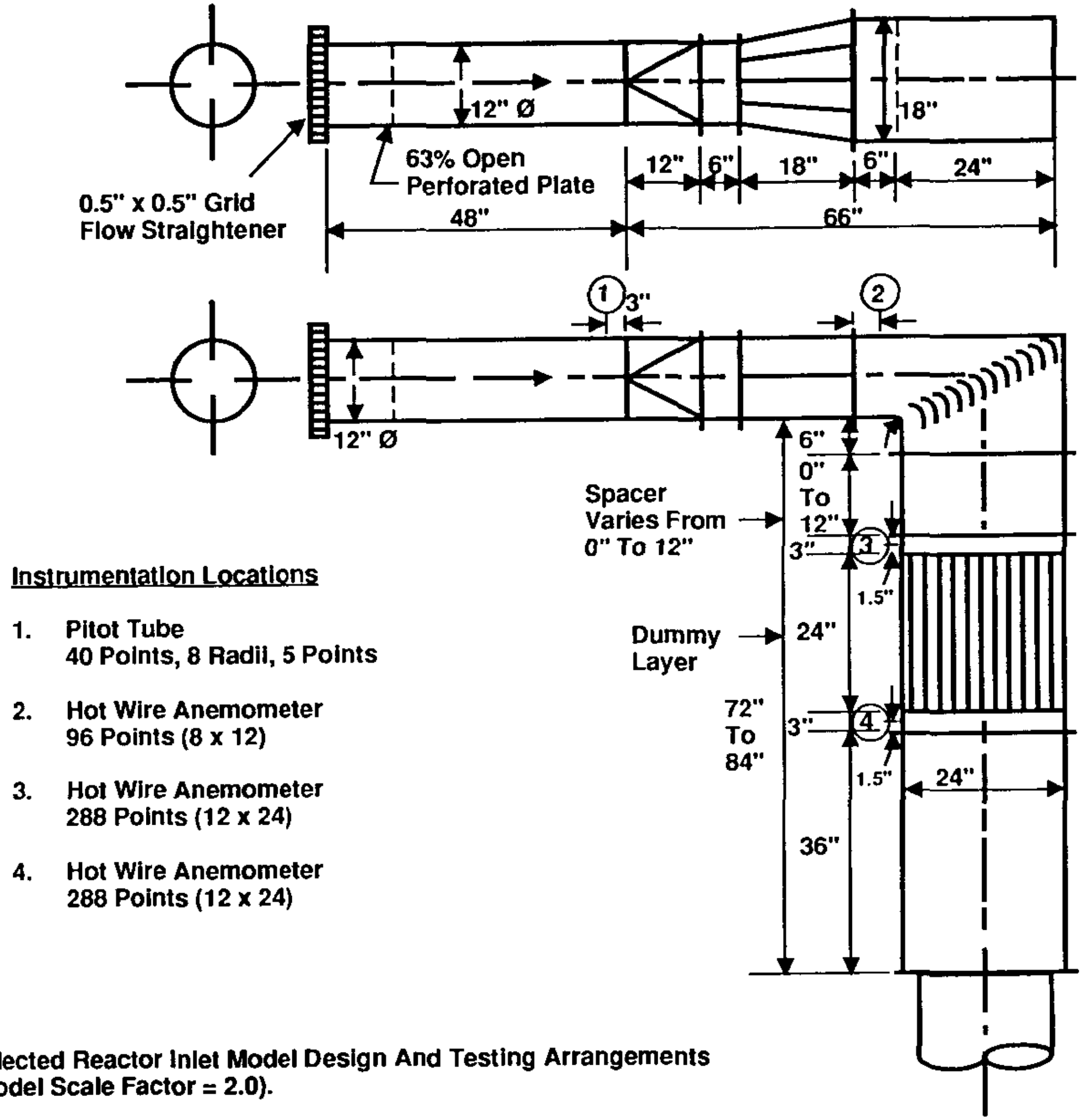


Figure 3. Selected Reactor Inlet Model Design And Testing Arrangements (Model Scale Factor = 2.0).

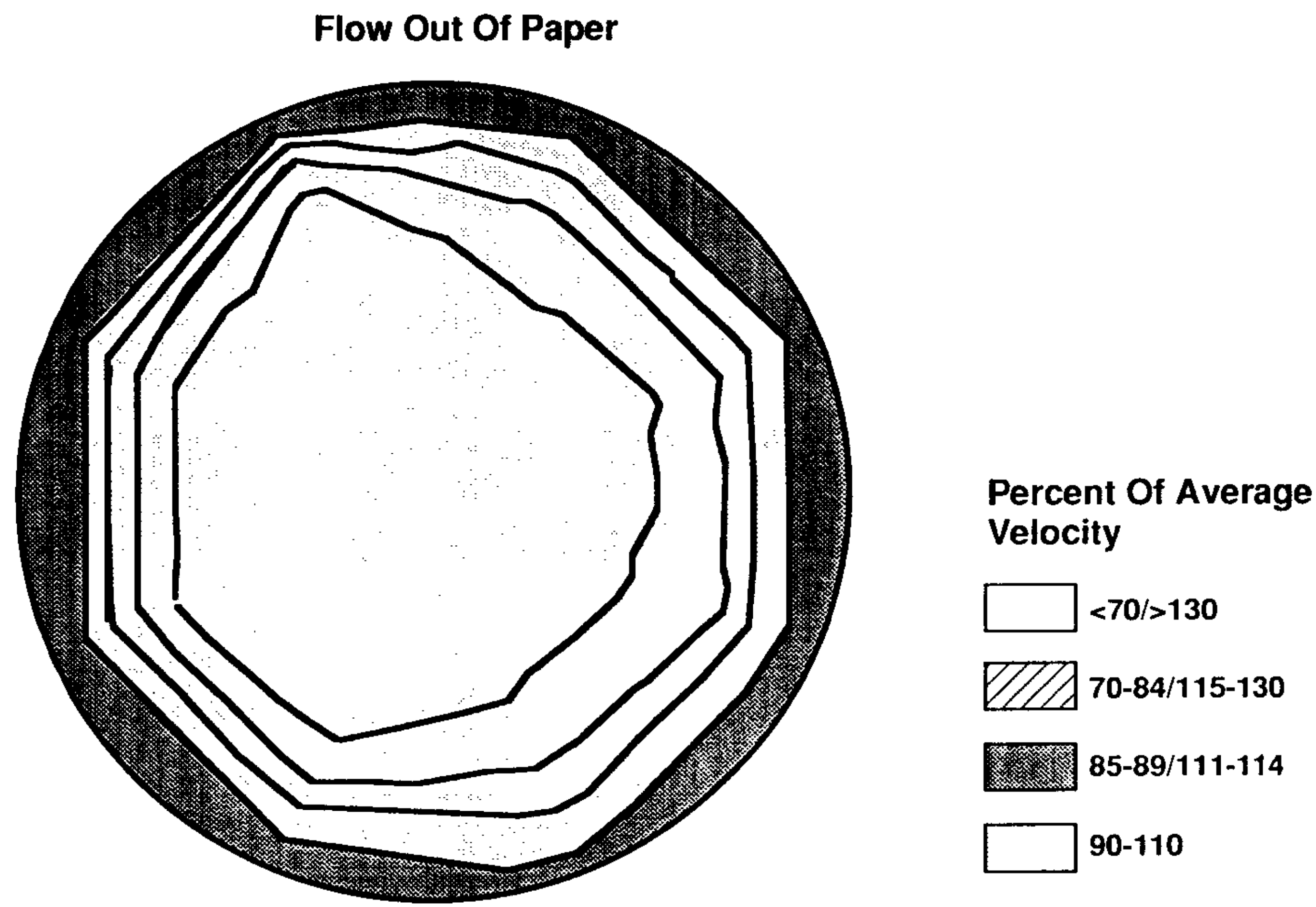


Figure 4. Velocity Profile Data for Round Piping Ductwork in Reactor Inlet Model at Location 1.

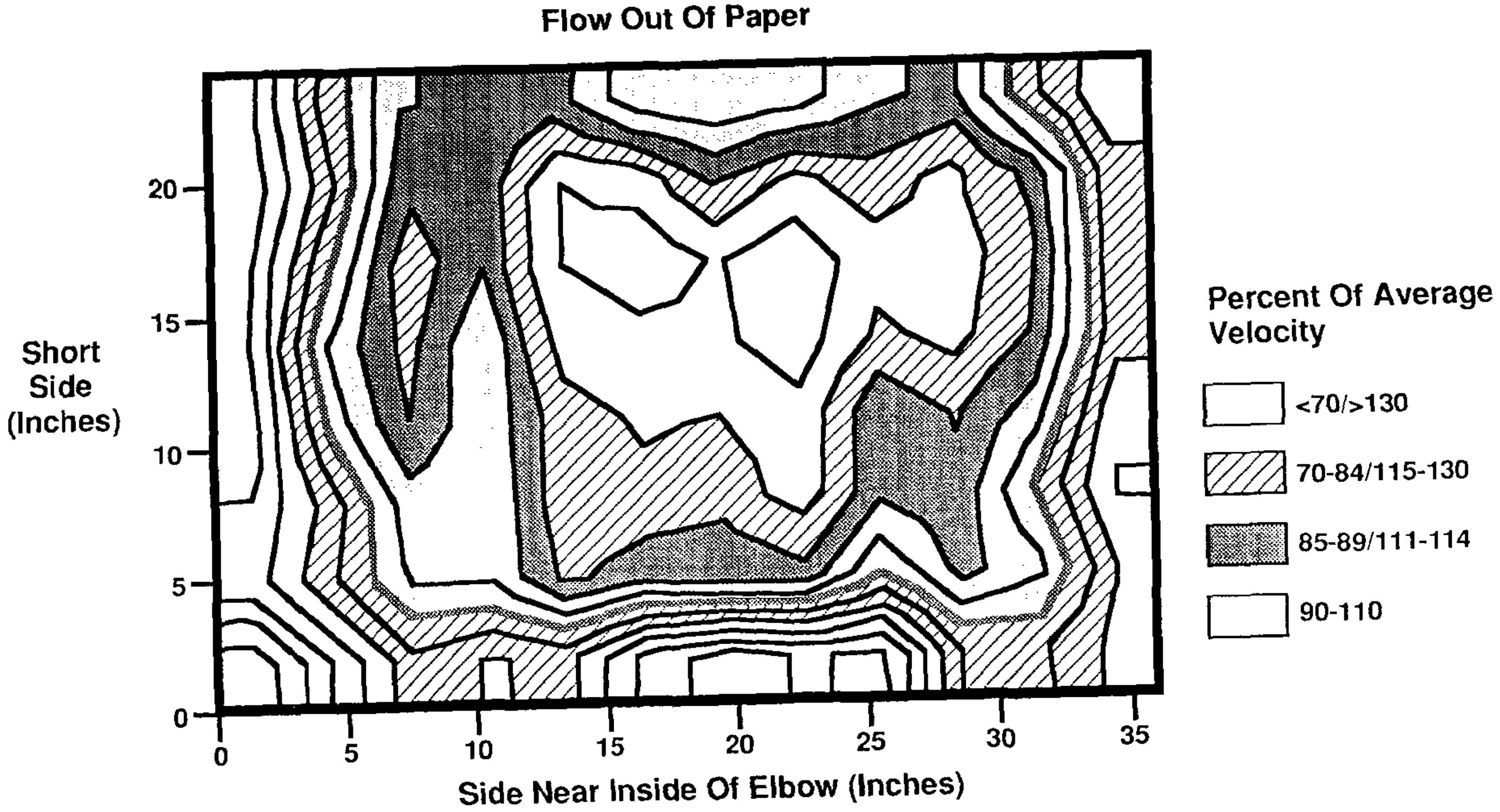


Figure 5. Initial Velocity Profile Data at Location 2, Diffuser Outlet, With Poor Uniformity Results (No Resistance Pipe).

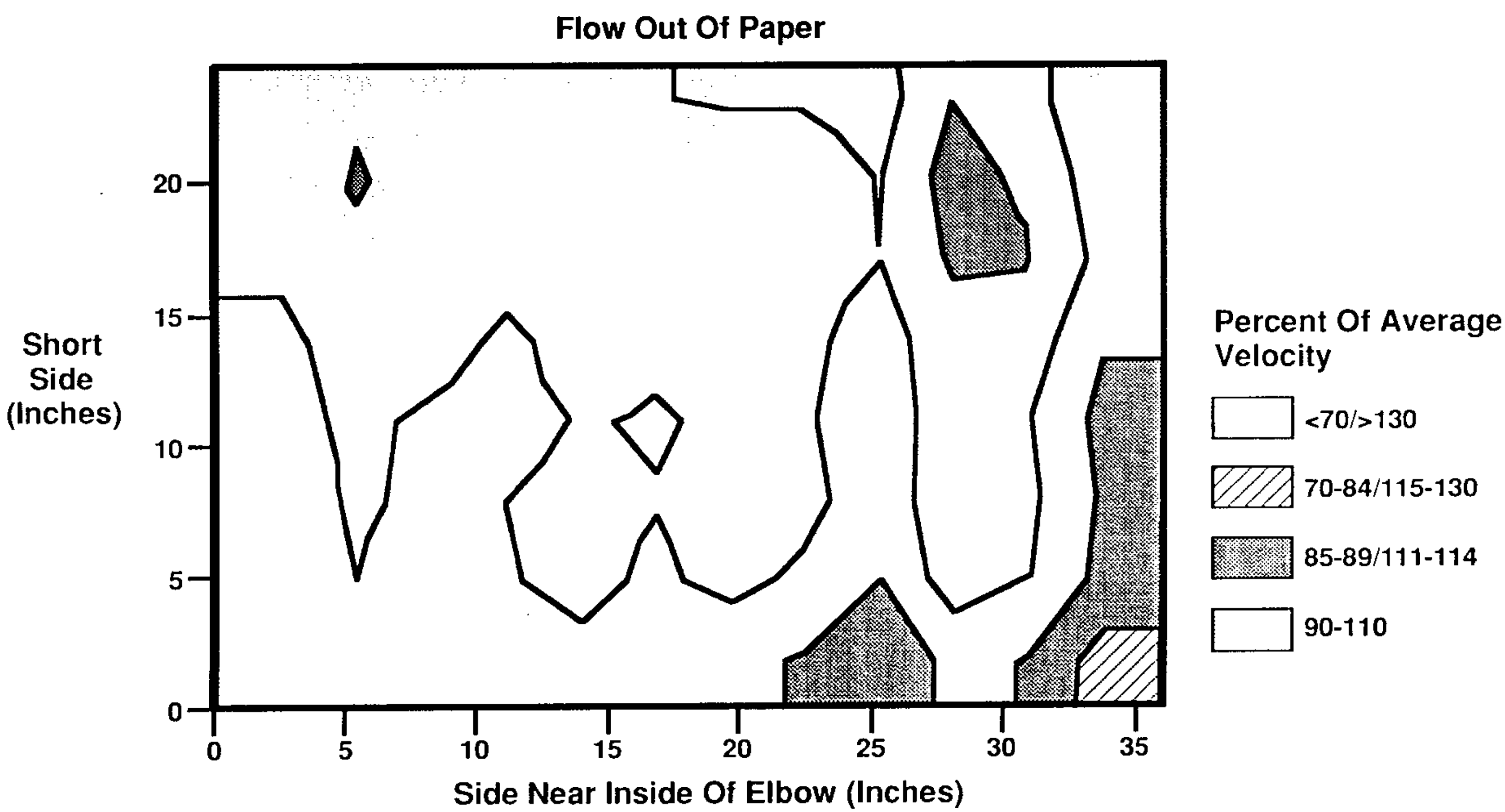


Figure 6. Improved Velocity Profile Data at Location 2, Diffuser Outlet, With Resistance Pipes Near Diffuser Inlet.

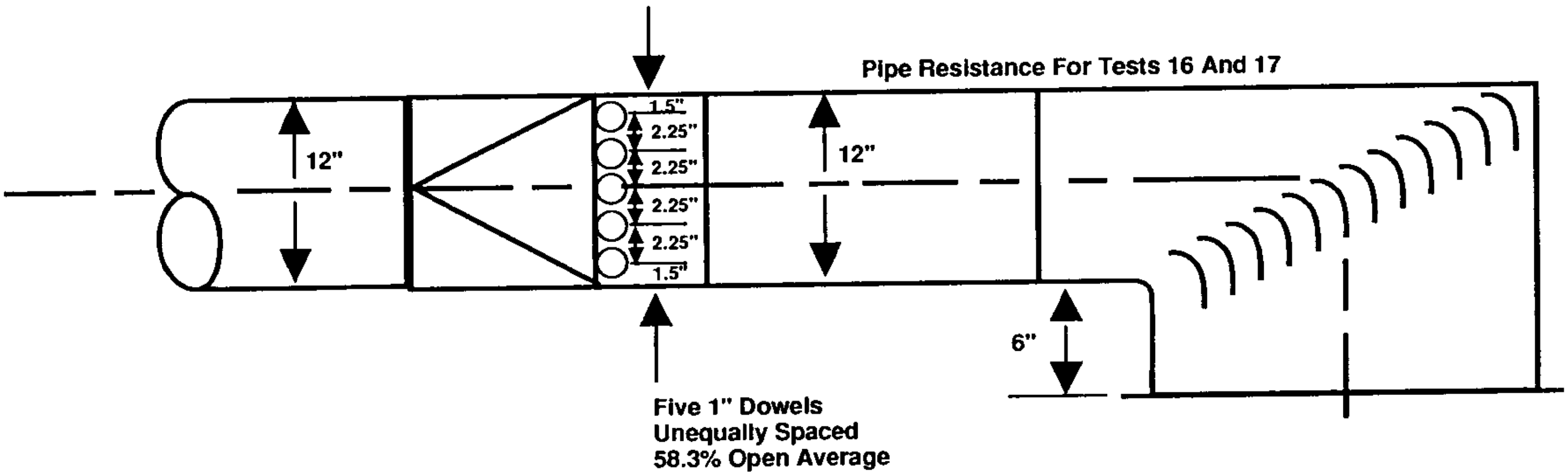


Figure 7. Detailed Geometry of the Resistance Pipes.

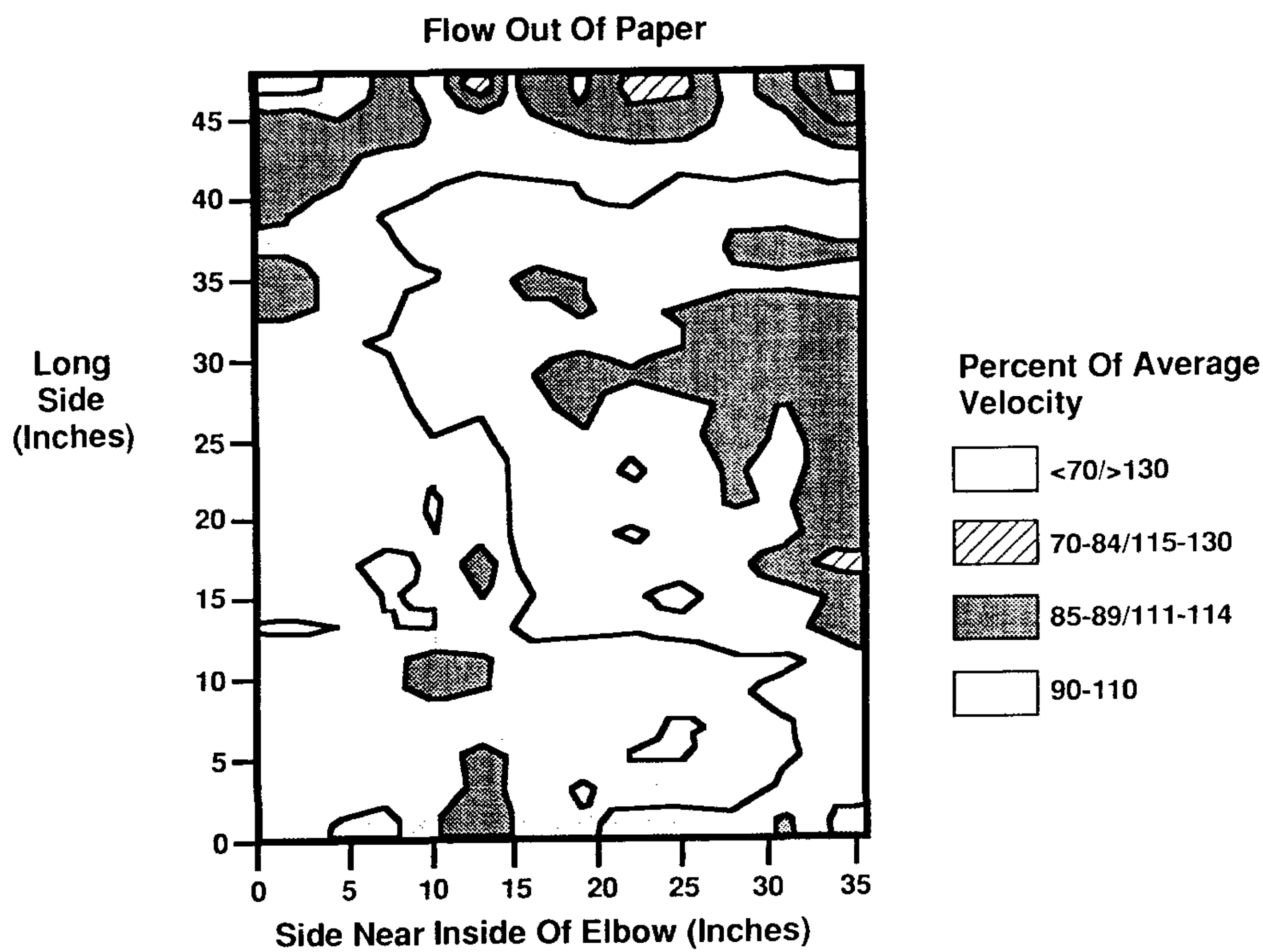


Figure 8. Initial Velocity Profile Data at Location 4, Dummy Layer Outlet, With Poor Uniformity Results (No Spacer, No Resistance Pipes).

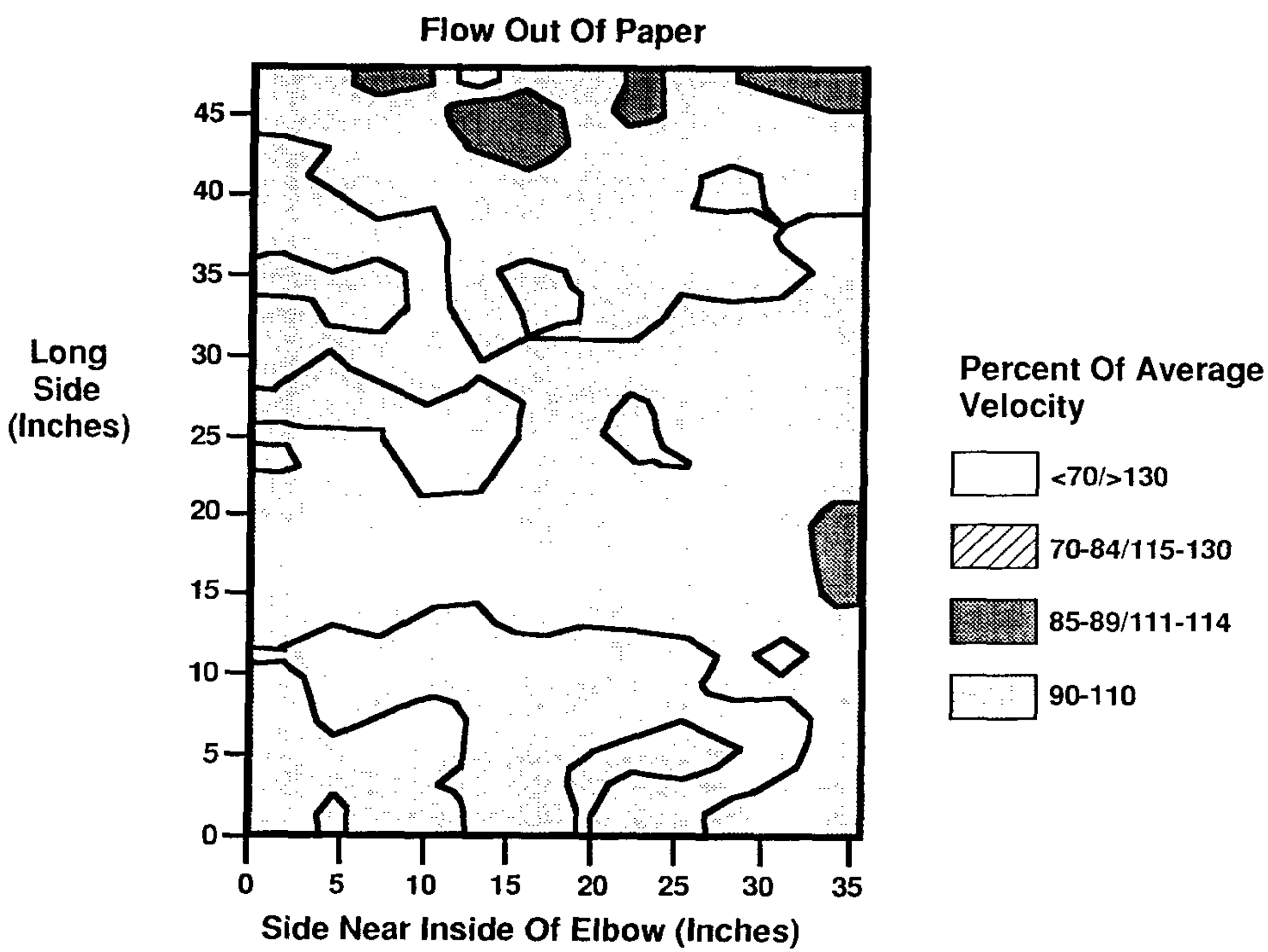


Figure 9. Improved Test Results at Location 4, Dummy Layer Outlet, With Optimum Design and Resistance Pipes (No Spacer).

# SESSION 5:
# Coal Processing Systems

*Chair: Douglas M. Jewell, DOE METC*

## DESIGN, CONSTRUCTION AND START-UP OF ENCOAL MILD COAL GASIFICATION PROJECT

### OBJECTIVES

ENCOAL's overall objective for their Mild Coal Gasification Project is to further the development of full sized commercial plants using the Liquids From Coal (LFC) Technology. In support of this overall objective, the following general objectives were established for the project:

1. Provide products for test burns
2. Develop data for the design of future commercial plants
3. Demonstrate plant and process performance
4. Provide capital and operating cost data
5. Support future LFC Technology licensing efforts

Specifically, the objectives for the period ending September 30, 1992 which includes completion of Phase II and the start of Phase III are as follows:

1. Complete all construction activities and have DOE review
2. Effectively train operations and support staff
3. Prepare Commissioning, Start-up, Shut-down and Test Plans
4. Complete all HAZ-OP and environmental permitting requirements
5. Commission and test plant piping and equipment systems
6. Start-up and operate plant for at least 24 hours in an integrated mode and make specification products
7. Submit public design report
8. Prepare Evaluation Report and receive approval on ENCOAL's Continuation Application
9. Perform plant modifications as required to improve operations
10. Deliver initial products to test burn customers

All of the specific objectives for this period have been met except for the delivery of products. This is because the plant has not yet had continuous runs sufficient to make the required volumes of products. A significant number of plant modifications have been made to improve plant operability and reliability and move closer to the last objective.

## BACKGROUND INFORMATION

### General Description

ENCOAL Corporation is a wholly owned subsidiary of Shell Mining Company (SMC) formed for the purpose of entering into a Cooperative Agreement with the DOE and carrying out the Mild Coal Gasification Project. ENCOAL has been granted a license for the use of the LFC Technology from the technology owner, TEK-KOL, a 50-50 partnership between SGI International of LaJolla, CA and SMC.

The plant will use the LFC Technology to process subbituminous Powder River Basin coal. Triton Coal Company's Buckskin Mine near Gillette, Wyoming is the host location and coal supplier. Two environmentally superior products are produced. The solid product, called Process Derived Fuel (PDF) is a stable, high-Btu fuel similar in composition and handling properties to eastern bituminous coals but very low in sulfur. Co-produced with PDF is a Coal Derived Liquid (CDL) that is similar in properties to a low sulfur number 6 fuel oil.

A substantial amount of pilot plant testing of the LFC process and laboratory testing of PDF and CDL was done by SGI and SMC. The pilot plant tests proved that the process was viable, predictable and controllable and could consistently produce PDF and CDL to desired specification. Laboratory testing, including PDF combustion tests, have yielded a wealth of information on both products. PDF does not exhibit spontaneous ignition tendencies, resorb moisture, or handle differently from its parent Buckskin coal. Ash properties are very comparable and combustion properties are excellent, even at relatively low residual volatility levels (<20%). CDL is different from petroleum derived oils due to its aromatic nature, but it should substitute directly for number 6 fuel oil according to the laboratory tests. It has a low viscosity at operating temperatures and is comparable in flash point, heat content and combustion properties. Low sulfur content, less that 1.2 pounds per million Btu, is the highlight of both products.

Feasibility studies, preliminary design, economics and some detailed design work was done by SMC in 1988. In June of 1988, an application was submitted to the Wyoming Department of Environmental Quality Air Quality Division for a permit to construct a 1000 ton per day LFC plant at Buckskin. This permit was approved in July, 1990. Work on the project was suspended in September, 1988 pending acquisition of risk sharing partners.

ENCOAL submitted a proposal to the DOE in August of 1989 as part of Round III of the Clean Coal Technology Program. The project was selected in December, 1989 and a Cooperative Agreement signed in September of 1990. A contract was awarded to The M.W. Kellogg Company for engineering, procurement and construction and they began their work about the same time. Ground breaking took place in October of 1990. By July of 1991, the basic design work was complete and construction was well underway.

**Process Description**

The LFC Technology uses a mild gasification process or mild pyrolysis as some know it. Figure 1 is a simplified flow diagram of ENCOAL's application of the LFC Technology. The process involves heating coal under carefully controlled conditions. Nominal 3" x 0" run-of-mine coal is conveyed from the existing Buckskin Mine to a storage silo. The coal from this silo is screened to remove oversize and undersize materials. The 2" x 1/8" sized coal is fed into a rotary grate dryer where it is heated by a hot gas stream. The residence time and temperature of the inlet gas have been selected to reduce the moisture content of the coal without initiating chemical changes. The solid bulk temperature is controlled so that no significant amounts of methane, carbon monoxide, or carbon dioxide are released from the coal.

The solids from the dryer are then fed to the pyrolyzer where the temperature is further raised to about 1,000 degrees F on another rotary grate by a hot recycle gas stream. The rate of heating of the solids and their residence time are carefully controlled, since these parameters affect the properties of both solid and liquid products. During processing in the pyrolyzer, all remaining free water is removed, and a chemical reaction occurs which results in

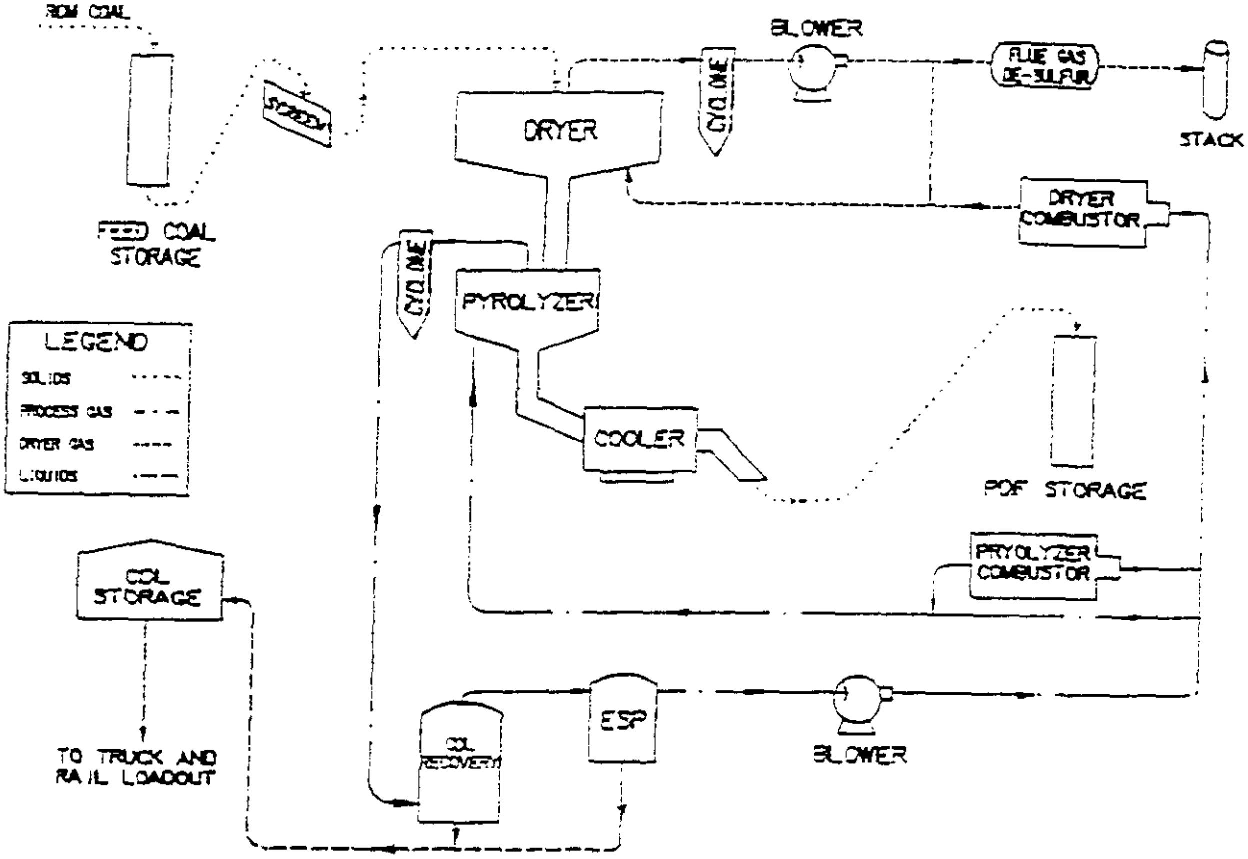


FIGURE 1. SIMPLIFIED FLOW DIAGRAM

the release of volatile gaseous material. Solids exiting the pyrolyzer are cooled to stop the pyrolysis reaction and transferred to a surge bin. Since the solids have no surface moisture and, therefore, are likely to be dusty, a dust suppressant is added as they leave the PDF product surge bin.

The gas produced in the pyrolyzer is sent through a cyclone for removal of the particulates and then cooled to stop any additional pyrolysis reactions and to condense the desired liquids. Only the CDL is condensed in this step; the condensation of water is avoided.

Most of the residual gas from the condensation unit is recycled directly to the pyrolyzer, while some is first burned in the pyrolyzer combustor before being blended with the recycled gas to provide heat for the mild gasification reaction. The remaining gas is burned in the dryer combustor, which converts sulfur compounds to sulfur oxides (SOx). Nitrogen oxide emissions are controlled via appropriate design of the combustor. The hot flue gas from the dryer combustor is blended with the recycled gas from the dryer to provide the heat and gas flow necessary for drying.

The off-gas from the dryer is treated in a wet gas scrubber and a horizontal scrubber, both using a water-based sodium carbonate solution. The wet gas scrubber recovers the fine particulates that escape the dryer cyclone, and the horizontal scrubber removes most sulfur oxides from the flue gas. The treated gas is vented to a stack. The spent solution is discharged into a pond for evaporation. The plant has several utility systems supporting its operation. These include nitrogen, steam, natural gas, compressed air, bulk sodium carbonate and a glycol/water heating and cooling system.

**PROJECT DESCRIPTION**

The ENCOAL project involves the design, construction and operation of a 1000 ton per day mild coal gasification demonstration plant and all required support facilities. A significant reduction in work scope and cost is being realized on the project due to the existence of the host Buckskin Mine. Coal storage and handling facilities, rail loadout, access roads, utilities, office, warehouse and shop facilities are all present at the Mine site and significantly reduced the need for new facilities for the ENCOAL project. Operations staff, supervision, administrative services and site security are being provided under a contract with Triton Coal Company. The balance of the project requirements are being provided by ENCOAL and its other subcontractors.

The project is divided into three phases as follows:

Phase I - Design and Permitting
Phase II - Construction and Start-Up
Phase III - Operation, Data Collection, and Reporting

Two budget periods encompass the work, the first covering Phases I and II and the second covering Phase III. A typical Work Breakdown Structure has been developed for the project.

Kellogg's scope of work included home office design, project coordination, field construction supervision, scheduling, project controls, procurement and project management. ENCOAL provided the technical support, field engineering and inspection. Kellogg and ENCOAL worked very closely during design and construction as an integrated team with each organization providing multi-skilled people, thus reducing total costs.

An important part of the engineering that was handled by ENCOAL in parallel with the Kellogg work was the PLC programming and process control systems design. A subsidiary of SGI, SG Tech, was contracted to assist in the application of their computer control technology to the ENCOAL project. Ultimately, it is anticipated that the plant process can be controlled and optimized using predictive feed forward and an adaptation of artificial intelligence methods.

ENCOAL and Triton handled the operations planning, training, maintenance planning, staffing, plant pre-commissioning and start-up, data gathering and initial plant operation. These activities took place in Phase II. Preparation of written plans and manuals was a part of these activities. All permitting requirements, and they were substantial, were handled by ENCOAL. Phase III operation is now underway with Triton providing the operating and maintenance staff and ENCOAL providing the technical direction.

The ENCOAL project is demonstrating for the first time the integrated operation of several unique process steps:

a. Coal drying on a rotary grate using convective heating
b. Coal devolatilization on a rotary grate using convective heating
c. Hot particulate removal with cyclones
d. Integral solids cooling and deactivation/passivation
e. Combustors operating on low-Btu gas from internal streams
f. Solids stabilization for storage and shipment
g. Computer control and optimization of a mild coal gasification process
h. Dust suppressant on PDF solids

The product fuels are expected to be used economically in commercial boilers and furnaces and to significantly reduce sulfur emissions at industrial and utility facilities currently burning high sulfur bituminous fuels or fuel oils thereby reducing acid rain-causing pollutants.

## RESULTS

### Construction and Field Engineering

The design and construction of the ENCOAL demonstration plant was done on a fast track basis, that is, these activities were extensively overlapped. Figure 2 is an overall plot plan of the work site for convenient reference. Even though the design work had just started, field construction crews mobilized in early October, 1990. By the end of the year, all of the major underground foundations were done and the first silo was poured. Although activity slowed during the winter, by the spring of 1992, the feed coal and PDF silos had been completed. All underground piping and equipment foundations were also done.

The mechanical erection and instrumentation/electrical subcontractors were mobilized in March and July of 1991 respectively. The first piece of major equipment, the PDF cooler, arrived in May, 1991. Structural steel began arriving in Late June, 1991 and was delivered on schedule from that point on, thus avoiding any delays in the building erection. Some of the major equipment was a different story, however. Blowers, pumps, combustors and some process vessels were slow to be requisitioned and even slower to be delivered by the vendors. Some delays in construction were then inevitable. In spite of these problems, construction went well by working around the missing pieces and by the end of 1991 most of the equipment was in place and the buildings were ready to be enclosed.

ENCOAL moved into its new offices in the fall of 1991 upon completion of the offsites buildings contract. Also included in this package was a pump house, motor control center and substation building. Above ground piping, storage tanks and CDL loading

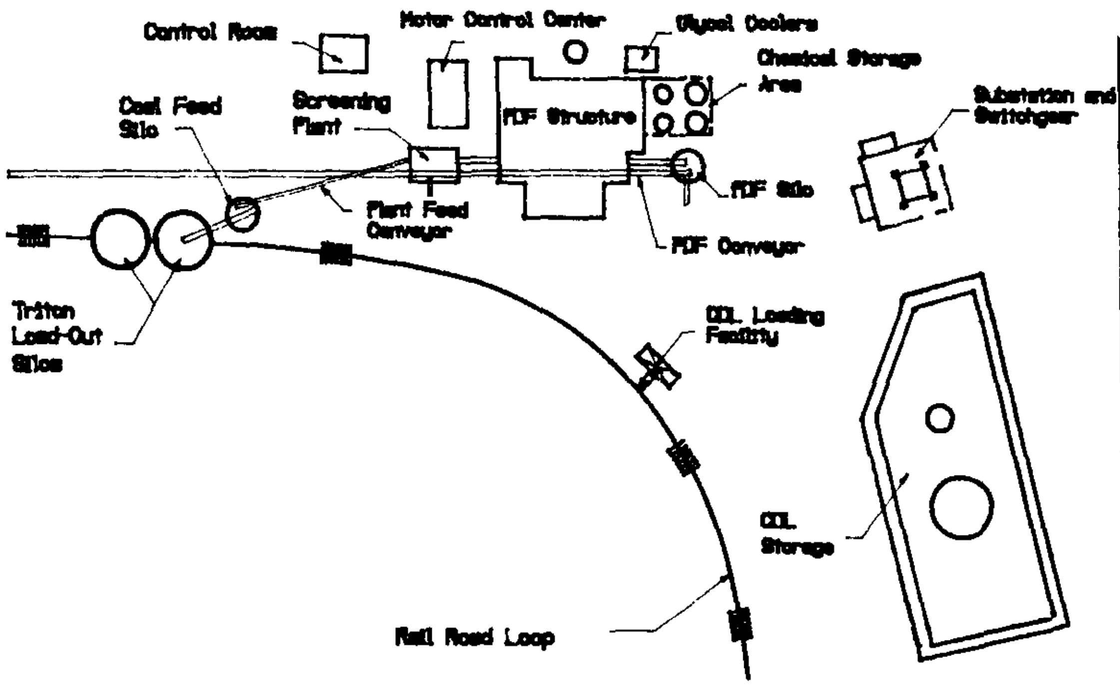


Figure 2. ENCOAL Project Plot Plan

facilities external to the process building were done under separate contracts and were completed by the end of 1991. Conveyors for the feed coal silo and into the plant were only partially done mainly because of misfits and because the building structures needed to be completed before final assembly. A significant amount of field engineering and retrofitting was required on these conveyors.

In February of 1992, the last piece of major equipment, the dryer cyclone, was set and the last of the structural steel put in place. Testing of piping systems had already begun on the lower floors. Turnover of major plant systems, a direct measure of completion, began in February and March. About this time, the conveyor and screening building misfits were corrected and final assembly accomplished. Pressure testing of all piping, except the large diameter ducts, was completed with few problems and turned over in mid March. Two of the plant's blowers were used to test the large diameter ducts, some refractory lined, some internally clad and some coated, to 22 inches of water or four times operating pressure. Numerous leaks were found and several cycles of fixing and testing were required before the final turnover and acceptance of the mechanical systems on April 17, 1992. Instrumentation and electrical turnover occurred on May 15 but many systems were in ENCOAL's control well before then. The 90% completion review with DOE was held April 7-9.

ENCOAL and Kellogg used the services of 22 subcontractors in the performance of the construction work. Total employment peaked at about 175 at one point, although more than 300 were present on site at various times. More than 320,000 manhours were required for this phase of the project. The cost for the first budget period which included design and construction was projected to be $51,200,000 and the project team held the costs to that figure through the use of a good controls plan and tight budget constraints.

Field engineering represented a significant effort on this project because of the fast track method used. Home office engineering was cut short without the normal level of detail engineering completed largely because vendor information was late in arriving and construction was underway. This added to the field engineering requirements. Field engineering also included environmental permitting. Revisions to the facilities and the process design subsequent to the issue of the original permits required modifications to those permits. The air permit, pond permits and additions to Triton's mining permits all had to be modified. Approval was secured on all of the required permits in a timely manner and did not affect construction. The only remaining permit item is the Wyoming Air Quality Division Permit To Operate which can only be issued after plant emissions testing. This is expected in the near future. ENCOAL's third and final HAZ-OP review was conducted the week of March 2 and all recommendations and questions were answered prior to putting heat in the plant.

One of the highlights of the construction effort was the excellent safety record achieved by ENCOAL, Kellogg and their sub-contractors. The lost time incident rate of 0.6, one in 320,000 manhours, was remarkable compared to the national average of 6.2. The MSHA recordables were one third of the national average at 4.6 per 200,000 manhours. This achievement was the result of a strong safety plan that incorporated both positive reinforcement and recognition with firm rules and discipline.

**Commissioning and Start-up**

As discussed, Triton Coal Company is operating the demonstration plant under a contract with ENCOAL. They have furnished a plant manager, plant engineer and 13 operating and maintenance personnel. Training of this staff, as well as ENCOAL's technical staff, took place from February 24 through April 10, 1992. The training consisted of prepared classroom sessions in the morning and hands-on maintenance and pre-commissioning activities in the afternoons. Teaching was done by ENCOAL's technical staff with help from consultants in some areas. Initial Commissioning Plans, Start-up and Shut-down Plans were also finalized during this time. Preventative maintenance plans, vessel entry procedures, safety and personnel protection procedures and operations plans were developed by the staff before, during and after the training period.

In the afternoon session, the operations staff worked very closely with Kellogg and their sub-contractors, doing some inspection as well as pre-commissioning. Pressure tests were witnessed, vessels were inspected before closing and piping was cleaned and flushed. This effort enabled systems commissioning to begin by the end of April, only two weeks after mechanical turnover. Systems commissioning took longer than expected, however, largely due to the incomplete nature of instrument electrical hookups. A number of pieces of equipment had to be repaired before they would work and leaks were discovered in the shells of the dryer and pyrolyzer during one of the pressure tests even though they did not show up before. In addition, a number of repairs had to be made to the seals and latch hardware on all of the five explosion relief doors.

The result of all this work was a delay in the planned schedule of about a month before the plant was ready for coal.

Briefly, the planned sequence of events leading to full integrated operation of the plant can be summarized as follows:

1. Complete all loop checks and commissioning of individual systems.
2. Run both combustors and dry out refractory.
3. Operate complete dryer and pyrolyzer gas loops at operating temperatures.
4. Run coal through the plant cold and test all solids handling systems.
5. Run plant in integrated mode and make specification products for at least 24 hours.

The first two items were completed by May 12. Item three was done on May 23 following modifications to the combustors. Coal was first put in the plant on May 30 and on June 16 the first 24 hour run was completed where PDF and CDL were made. Since the first run, three additional hot coal runs have been made where close to specification products have been made. These runs have varied from 6 hours to 28 hours. However, it should be noted that the entire plant and all utilities run for much longer than the time coal is actually going in the unit due to the heat up and cool down times. The minimum run time is usually three days. The longest run so far was 6 days.

**Plant Modifications**

A great deal has been learned from the initial plant operations. Each run is followed by an evaluation of the data gathered by the plant's state of the art computer systems. A number of plant modifications and equipment repairs have resulted to correct the problems identified. These changes can be categorized into the following general areas:

1. Equipment repairs
2. Pump and blower capacities and pressures
3. Combustor controls
4. Dust collection
5. Process variables

**Equipment Repairs.** The most significant repairs to date have been to the pyrolyzer and dryer. During the third hot run, a diverter plate hooked the rotating grate due to heat expansion and improper adjustment and damaged several stainless steel beams. In both units, the seals between the inlet gas plenum and the discharge gas plenum required additional parts to keep them in place. These repairs required entry into both vessels and took more than three weeks.

Repairs have also been required on the seals on the primary gas blower in the dryer loop. These failed each of the first three times the plant operated and leaked process gases into the building. A modified design was installed and worked fine on the last run. Other minor repairs have been made to the conveyor's like dribble collection, plug chute switches, access doors and idlers to improve reliability and spillage problems. There are no outstanding equipment problems at this time.

**Pumps and Blowers.** The problems in this area can be summed up as too big or too little. The combustor forced draft blowers had too much capacity and larger bypass valves had to be added to control air flow. The firewater pump put out too much pressure and had to be relieved. Pumps on the cooling water and process water systems turned out to be much too small since there is more water being circulated than expected. The supply pump has already been replaced and a new process water pump is being ordered. These items have not prevented the plant from running at design, but replacement will reduce manual operations and improve performance of the dust collection systems.

**Combustor Controls.** Heat for the dryer and pyrolyzer are provided by two sophisticated low Btu gas combustors. These combustors must also control emissions from the plant and therefore are critical parts of the overall process. The control systems for these units are highly cascaded and complex. In the runs to date these systems have demonstrated unacceptable swings in air to fuel ratios and heat output. A number of software and hardware corrections have been implemented on the dryer combustor and on the last hot run, it behaved very well. These same corrections have now been made on the pyrolyzer combustor.

**Dust Collection.** In all of the laboratory testing and pilot plant work that SGI and SMC did, PDF was a non-dusty product, especially when treated with SMC's proven dust inhibitor, MK. Indeed in the first four hot runs, the PDF was not dusty. However, during the transition period when run-of-mine coal is handled or when ramping up or down from operating temperatures, the coal is only partially processed. This partially processed coal is very dusty to the point where continued operation was not possible due to the hazards of escaping dust and the cleanup problems it created. A patented wet scrubber design was provided on the feed coal side of the plant because the feed coal was known to be very dusty. Since no significant amounts of dust were anticipated in the demonstration plant on the product side of the process, no dust collection provisions were made.

After fighting the problem in the first two runs, it was decided to add dust collection at the discharge of the PDF cooler and on top of the PDF silo. Wet scrubbers were obtained and installed for this application. In the last two runs, the dust problem was gone. Some minor problems with handling the slurry from the dust collection systems and from plant washdown still exist, but these do not affect the process.

**Process Variables.** A number of process variables are different under actual plant conditions than the theoretical plant design predicted. The most significant of these items is stopping the mild gasification reaction at the desired point. This is accomplished by solids quenching prior to the PDF cooler. If the mild gasification reaction is not stopped in the quenching step, heavy hydrocarbon vapors are released outside of the pyrolyzer loop where they are supposed to be collected. The result is a mess! Operating data has shown that the reactions take place for a longer period of time and at lower temperatures than predicted. In the last two runs, the quenching was adjusted as needed and the problems did not occur.

Heat loss in the ESP's and ductwork downstream of the CDL recovery column is much higher than predicted. This is because the actual surface area of the system is larger than the original design and it isn't insulated. The result is water condensation in the CDL product. Three inches of insulation is now being added to this system. Dust carryover in the pyrolyzer cyclone has also been occurring causing solids to be high in the CDL product. Low process gas flow rates, during start-up, seem to be the cause. The dryer and pyrolyzer blowers have been the most reliable pieces of equipment in the plant and they are adequately sized to handle a wide variety of flows, so in future runs the mass flowrate in the gas loops will be increased to make the cyclone more efficient.

These are a sampling of the kinds of plant modifications that have been required so far. Many of the plant systems have operated very well as designed. Noise levels in the plant are much lower than was expected based on the vendor data on individual pieces of equipment. Temperatures in the building are manageable, although some additional vent fans are being evaluated. Most of the utilities have been very reliable and once the initial leaks were repaired, the ductwork and refractory linings are in good shape. Surely there will be more plant modifications to do, but, hopefully, the major ones are done.

**Products.** PDF and CDL have been made in each of the four hot coal runs that have been attempted so far. However, the first and third runs were of such short duration that the material produced during the transient conditions of start-up and shut-down could not be segregated from the good products. Tests on the products from these runs were erratic. For both of the longer runs, that is greater than 24 hours of more or less steady state operation, laboratory tests are believable. Table 1 gives the results of the test of the run-of-mine coal and PDF made from that coal for runs two and four. It appears that run two is slightly over pyrolyzed and run four is under pyrolyzed. The CDL made in these two runs is shown in Table 2. As discussed above, the Basic Sediment and Water (BS & W) is higher than projected for the CDL long term.

**Table 1. Product Analysis - Solids As Received**

| | Run-Of-Mine | | PDF | |
|---|---|---|---|---|
| | Run 2 | Run 4 | Run 2 | Run 4 |
| Moisture | 31.3 | 28.6 | 1.6 | 6.7 |
| Ash % | 5.3 | 5.3 | 10.1 | 8.3 |
| Volatile % | 29.6 | 32.1 | N/A | 22.4 |
| Sulfur % | .40 | .44 | .74 | .42 |
| Btu/lb. | 8416. | 8416. | 12,227. | 11,754. |
| HGI | 61 | N/A | 59 | N/A |

**Table 2. Product Analysis - CDL**

| | Run 2 | | Run 4 | |
|---|---|---|---|---|
| | A | B | A | B |
| API Gravity | 3.0 | 6.9 | 3.1 | 4.5 |
| Pour Point °F | 92. | 62. | 75. | 90. |
| Heat Value Btu/lb. | 13,063. | 16,767. | 14,258. | 16,634. |
| BS & W % | 48.0 | 27.0 | 1.4 | 7.1 |
| Flash Point °F | >140. | >140. | N/A | N/A |
| Sulfur % | .76 | 1.5 | .30 | N/A |
| Ash % | .24 | .08 | .07 | N/A |

**Note:** N/A means not available

No data is yet available on the yield per ton of input coal, but based on the heat content of the plant make gas used as fuel in the combustors, more hydrocarbons are being generated than projected. A concern of many potential customers, the dustiness appears to be very well controlled by the MK and the removal of fines in the process. Stability of the PDF with respect to moisture resorption and spontaneous ignition is still not well established. The size consist of the PDF product is considerably smaller than that obtained in any of the pilot plant operations. It is expected that the PDF product will continue to be small, but this will help the bulk density and it has been shown to be acceptable from a dust perspective.

**FUTURE WORK**

In the next year, ENCOAL plans to operate the demonstration plant at full capacity producing PDF and CDL for test burns. It is possible that sometime during this period, some coal will be run through the plant from sources other than the Buckskin Mine. The plant facilities will also be thoroughly tested during this time so that the capability of each piece of equipment as well as the total plant is known. There will also be a series of tests to vary process conditions and determine the affect on product qualities. In the near future, the plant emissions will be measured at operating conditions to verify permit compliance and pave the way for issuance of ENCOAL's Permit To Operate from the Wyoming DEQ.

Specifically, in the next few months, ENCOAL will deliver its first unit train of PDF product and the first tank cars of CDL. The computer control system that operates the plant will be put in the automatic mode for start-up, operation and shut-down. Data gathering on the process will be routine and done mostly by the computer system. Work on the design and economics for a large commercial plant will begin as soon as the demonstration plant is operating normally. The goal is to have at least one contract for a commercial plant within two years.

ENCOAL will also continue to abide by the Cooperative Agreement. The public design report will be finalized by December 1992. Topical reports and monthly and quarterly reports will continue to be produced on time. Patent disclosures will be submitted to the DOE and to the patent office as appropriate. In one year, an operations review will be held and informal reviews will be held approximately quarterly. At least two additional contracts for PDF for test burns should also be obtained.

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# ROSEBUD SYNCOAL™ PARTNERSHIP

# ADVANCED COAL CONVERSION PROCESS

# DEMONSTRATION PROJECT

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## Introduction

Rosebud SynCoal$^{TM}$ Partnership's Advanced Coal Conversion Process (ACCP) is an advanced thermal coal drying process coupled with physical cleaning techniques to upgrade high-moisture, low-rank coals to produce a high-quality, low-sulfur fuel.

The coal is processed through two vibrating fluidized bed reactors that remove chemically bound water, carboxyl groups, and volatile sulfur compounds. After drying, the coal is put through a deep-bed stratifier cleaning process to effect separation of the pyrite rich ash.

The process enhances low-rank western coals with moisture contents ranging from 25-55%, sulfur contents between 0.5 and 1.5%, and heating values between 5,500 and 9,000 Btu/lb. The upgraded stable coal product has moisture contents as low as 1%, sulfur contents as low as 0.3%, and heating values up to 12,000 Btu/lb.

A 45 ton per hour demonstration plant constructed adjacent to Western Energy Company's Rosebud mine unit train loadout facility near the town of Colstrip in southeastern Montana has begun initial operation. Rosebud SynCoal's demonstration plant is sized at about one-tenth the projected throughput of a multiple processing train commercial facility.

Initial operations discovered the normal variety of equipment problems which delayed operational and process testing. As operational testing has proceeded some product quality issues have emerged, although the product has met the BTU, moisture and sulfur specifications. The project team is continuing process testing and is working toward resolution of the operational and process issues.

The ACCP Demonstration Facility is a U.S. Department of Energy Clean Coal Technology Project with 50% funding from the DOE and 50% from the Rosebud SynCoal Partnership.

The Rosebud SynCoal Partnership is a venture involving Western SynCoal Company and Scoria Inc.. Western SynCoal is a subsidiary of Western Energy Company (WECo) which is a subsidiary of Entech Inc., Montana Power Company's non-utility group. Scoria Inc is a subsidiary of NRG Inc., Northern States Power's non-utility group.

## Status of Development

Much of the early ACCP development was performed using a small, 150 pound per hour pilot plant located at the Mineral Research Center, south of Butte, Montana. Up to 100 ton lots were produced to assess stability during shipping and handling as well as chemical characteristics. A variety of coals and process conditions were tested to determine the process capabilities.

Development is continuing as construction and startup has been completed and initial operation is underway on the 300,000 ton per year demonstration plant at Western Energy's Rosebud Mine near Colstrip, Montana.

## Process Description

In general the ACCP is a drying and conversion process using low pressure, superheated gases to process coal in vibrating fluidized beds. Two vibratory fluidized processing stages are used to heat and dry the coal followed by a water spray quench and a vibratory fluidized stage to cool the coal. The solid impurities are then removed from the dried coal using pneumatic separators. Other systems servicing and assisting the coal conversion system are:

Product Handling
Raw Coal Handling
Emission Control
Heat Plant
Heat Rejection
Utility and Ancillary

The nominal throughput of the demonstration plant is 1,640 tons per day (tpd) of raw coal, providing 988 tpd of coarse coal product and 240 tpd of coal fines (minus 20 mesh). The fines are collected and briquetted, giving a combined product rate of 1,228 tpd of high-quality, clean coal product. The central processes are depicted in Figure 1, the Process Flow Schematic.

### *Coal Conversion*

The coal conversion is performed in two parallel processing trains. Each consisting of two 5-feet wide by 30-feet long vibratory fluidized bed dryer/reactors in series, followed by a water spray quench section and a 5-feet wide by 25-feet long vibratory cooler. Each processing train is fed 1,139 pounds per minute of sized coal.

In the first-stage dryer/reactors, the coal is heated using recirculated combustion gases, removing primarily surface water from the coal. The coal exits the first-stage dryer/reactors, at a temperature slightly above that required to evaporate water and is gravity fed into the second-stage dryer/reactors. Where the coal is heated further using a superheated gas stream, removing water trapped in the pore structure of the coal, and promoting decarboxylation. The superheated gasses used in the second stage are actually produced from the coal. The make-gas from the second stage system is used as an additional fuel source in the process furnace incinerating all the hydrocarbon gases produced in the process. The particle shrinkage that liberates ash minerals and imparts a unique cleaning characteristic to the dried coal also occurs in the second stage. As the coal exits the second-stage dryer/reactors, it falls through vertical quench coolers where process water is sprayed onto the coal to reduce the temperature. The water vaporized during this operation is drawn back into the second-stage exhaust gas. After quenching, the coal enters the vibratory coolers where the coal is contacted by cool inert gas. The coal exits the cooler at less than 150 degree F and is conveyed to the coal cleaning system. The cooler exit gas is cooled by direct contact with water prior to returning to the vibratory fluidized coolers.

### *Coal Cleaning*

The coal entering the cleaning system is screened into four size fractions: plus 1/2 inch, 1/2 by 1/4 inch, 1/4 inch by 6 mesh, and minus 6 mesh. These streams are fed in parallel to four deep-bed stratifiers (stoners), where a rough specific gravity separation is made using fluidizing air and a vibratory conveying action. The light (lower specific gravity) streams from the stoners are sent to the product conveyor; the heavy streams from all but the minus 6 mesh stream are sent to gravity separators. The heavy fraction of the minus 6 mesh stream goes directly to the waste conveyor. The gravity separators, again using air and vibration to effect a separation, each split the coal into light and heavy fractions. The light stream is considered product; the heavy or waste stream is sent to a 300 ton storage bin to await transport to an off site user or alternately back to a mined out pit disposal site. The dry, cool, and clean product from coal cleaning enters the product handling system.

### *Product Handling*

Product handling conveys the clean product coal to two 6,000 ton capacity concrete silos and allows unit train loading with the mine's tipple loadout system.

### *Raw Coal Handling*

Raw coal from the existing stockpile is screened to provide 1 x 1/4 inch feed for the ACCP process. Coal rejected by the screening operation is conveyed back to the active stockpile. Properly sized coal is conveyed to a 1,000 ton raw coal storage bin which feeds the process facility.

### *Emission Control*

The coal cleaning area fugitive dust is controlled by placing hoods over the sources of fugitive dust conveying the dust laden air to fabric filter(s). The bag filters can remove 99.99 percent of the coal dust from the air before discharge. All fines report to a briquetter and ultimately the product stream.

Sulfur dioxide emission control philosophy is based on injecting dry sorbent into the ductwork to minimize the release of sulfur dioxide to the atmosphere. The sorbent, sodium bicarbonate, is injected into the first stage dryer gas stream as it leaves the first stage dryers to maximize the potential for sulfur dioxide removal while minimizing reagent usage. The sorbent, having reacted with sulfur dioxide, is removed from the gas streams in the particulate removal systems. A 60 percent reduction in sulfur dioxide emissions should be realized.

### *Heat Plant*

The heat required to process the coal is provided by a natural gas fired process furnace. This system is sized to provide a heat release rate of 58 MM BTU/hr. Process gas enters the furnace and is heated by radiation and convection from the burning fuel. Process make gas from coal conversion is used as fuel in the furnace. A commercial scale plant would most likely use a coal fired process furnace.

### *Heat Rejection*

Heat rejection from the ACCP is accomplished mainly by releasing water and flue gas to the atmosphere through the exhaust stack. The stack design allows for vapor release at an elevation great enough that, when coupled with the vertical velocity resulting from a forced draft fan, dissipation of the gases is maximized. Heat removed from the coal in the coolers is rejected using an atmospheric induced-draft cooling tower.

*Utility and Ancillary Systems*

The coal fines that are collected in the conversion, cleaning and material handling systems are gathered and conveyed to a surge bin. The coal fines are then briquetted and returned to the product stream.

The common facilities include a plant and instrument air system, a fire protection system, and a fuel gas supply and distribution system.

The power distribution system includes a 15 KV service, a 15 KV/5 KV transformer, a 5 KV motor control center, two 5 KV/480 V transformers, two 480 V load distribution centers, and six 480 V motor control centers.

Control of the process is fully automated including duel control stations, duel programmable logic controllers, distributed plant control, and data acquisition hardware.

## Product Chemistry

Rosebud SynCoal's Advanced Coal Conversion Process yields a synthetic solid fuel that represents an evolutionary step in the coalification process. Western lignite and sub-bituminous coals are converted by the thermal environment of the ACCP to a higher rank fuel.

The ACCP changes the chemical composition and structure of the coal feedstock. The changes include: 1) a product that has a higher heating value than the coal feedstock; 2) a stable, hydrophobic product with much lower equilibrium moisture content that is less likely to spontaneously combust due to rehydration; and 3) a product that is readily transportable in open rail cars. The chemical changes effected by ACCP include the following:

- Increased aromaticity;
- Increase fixed carbon;
- Decreased hydrogen to carbon ratios;
- Decreased oxygen to carbon ratios; and
- Decreased oxygen functional groups.

The above changes are the result of the thermo-chemical reactions induced by the ACCP and result in the upgrade synthetic coal product.

The average analyses of the coal feedstock and upgraded product from the demonstration plant are shown in Table 1. The first section of the table shows standard proximate and ultimate coal analyses of the coal feedstock and the synthetic coal product. The second section of the table shows petrographic and additional analysis showing the upgrading of coal through the process.

Moisture is essentially eliminated from the coal during the ACCP. This moisture removal is due to thermal dehydration of the coal particle and the chemical condensation reactions which the feedstock experiences during its residence in the high temperature environment of the second-stage reactor bed.

The moisture-free analysis of the feedstock and the upgraded product also show that, to a large extent, both the volatile matter and the fixed carbon content is retained in the SynCoal product. This phenomenon is significant and desirable, because normally raw coal, when subjected to the temperatures of the ACCP, would undergo devolatilization and substantial gasification. Recent work has shown that devolatilization of low rank coals is very dependent upon the rate of heating (Ref. 1, 2.). In the ACCP, the coal is heated slowly, which, as described in the above references, favors dehydration and decarboxylation over devolatilization.

The ultimate analysis of the upgraded product compared with the Rosebud coal feedstock shows the result of the chemical reactions which have occurred: there is an increase in carbon, a decrease in both hydrogen and oxygen, and a decrease in both total and organic sulfur. Nitrogen, which is not affected by the ACCP, increases in percentage terms while staying constant in absolute terms. Oxygen is removed by the ACCP to the greatest extent of any of the coal elements. The oxygen removal is from decarboxylation reactions which drive off both carbon dioxide and water, dehydration reactions which drive off chemically bound water, and decarboxylation reactions which drive off carbon monoxide.

The increase in fixed carbon and decrease in hydrogen in the upgraded product results from chemical reactions which cause structural changes in the coal. These changes are a result of the coal becoming more aromatic and repolymerizing into a tighter ring structure. The reactions causing these changes result in pore destruction, shrinkage and fracture release of the pyrites and ash that are characteristics of the synthetically upgraded coal product.

The reductions in total and organic sulfur are due to two mechanisms. Most of the sulfur removal results from the mechanical removal of pyrites during the cleaning step. However, the ability to remove these pyrites is a result of the chemical repolymerization and consequent shrinkage of the organic components of the coal, which causes fracture release of the ash or mineral components. Chemical sulfur removal caused by the ACCP is due to the rearrangement of the organic molecules which release heteroatom sulfur. The minor amounts of carbon disulfide ($CS_2$), carbonyl sulfide (COS) and methyl mercaptan ($CH_3SH$) which appear in the make gas result from these heteroatom removal reactions.

The petrographic analysis of the feedstock and upgraded product in Table 1 measures characteristics of the organic matter from which the coal evolved. As organic matter changes into coal several of the different types of organic matter form "macerals" known as huminite, exinite and inertinite, These macerals are comparable to various minerals in the ash-forming components of the coal. In general, exinites have a higher hydrogen-to-carbon ratio than huminities, which have a higher hydrogen-to-carbon ratio than inertinities.

The maceral composition from the petrographic analysis indicates an increase in the coal rank of the upgraded product. Since the changes in the maceral composition are close to the accuracy limits of this analysis method, the conclusion of increased rank can not be based solely on maceral composition analysis. However, the last entry in the petrographic analysis, the reflective measurement, shows a very significant change between the feedstock and the upgraded product. The reflectance analysis is considered to be one of the most reliable indicators of coal rank. A reflective value of 0.42 indicated a sub-bituminous C coal. The upgraded product's reflectance of 0.51; however, indicates that the synthetic fuel product is similar to a high volatile bituminous class C coal. The increase in reflectance further indicates an increase in the aromaticity of the upgraded product on comparison to the feedstock.

The "Other Analysis" section of Table 1 shows several physical and chemical analysis results. As indicated, the surface area decreases from 288 $cm^2/g$ for the coal feedstock to 55 $cm^2/g$ for the upgraded product. This shrinkage is the most direct evidence of the destruction of the coal's pore structure through the ACCP. The reduced surface area is one reason why the equilibrium moisture content of the upgraded product is significantly reduced; the smaller surface area of the upgraded product cannot hold or attract as much water as the larger surface area of the feedstock. Furthermore, the water content of the upgraded product is also reduced because of the reduction of oxygen-containing functional groups. Since the upgraded product has less oxygen-containing functional groups, chemisorption of water through hydrogen bonding is retarded. Also, the hydrogen-to-carbon ratio (H/C) and the oxygen-to-carbon ration (O/C) are reduced in the upgraded product as a result of chemical reactions which increase the aromaticity of the coal and reduce its oxygen composition through decarboxylation reactions. The fact that these reactions occur is shown by the increase in apparent aromaticity (0.46 to 0.66 from feedstock for coal product) and the decrease in carboxyl group content (0.74% to 0.53%).

## Project Status

Rosebud SynCoal's ACCP Demonstration Facility was completed during the first quarter of 1992. Initial equipment startup was conducted from December 1991 through March 1992. Initial operations discovered the normal variety of equipment problems. The project's startup and operations groups worked together to overcome th initial equipment problems and achieve an operating system. Although the project is still experiencing difficulties with the dust handling equipment, the remainder of the plant has performed quite well.

The SynCoal product has displayed some tendency towards self heating that was not expected and appears to be related to the inadequate process conditions. The project's technical and operating team have initiated a process testing program in order to determine the cause of the product's lack of stability. A number of approaches have been partially successful; however, to date the demonstration product has not met the level of resistance to spontaneous combustion that was apparent in the earlier pilot plant work.

This has reduced the storage life and as a result delayed the full-scale test burn program; therefore, a more limited initial test burn program is being conducted with the Colstrip power plants and Montana Power's Corette station. The initial results from these tests have been very positive and the project team is looking forward to solving the self-heating problem and moving on with the full-scale combustion test program.

## Projections for the Future

The Rosebud Syncoal Partnership intends to commercialize the process by both preparing coal in their own plants and by licensing to other firms. The target markets are primarily the U.S. utilities, the industrial sector and Pacific

Rim export market. Current projections suggest the utility market for this quality coal is approximately 60 million tons per year. The Partnership's goal is to start construction on a commercial facility designed to produce 3 million tons per year in 1995.

## Conclusion

The ACCP is a relatively simple, low pressure, medium temperature coal drying and conversion process. The synthetic upgraded coal product exhibits the characteristics of reduced equilibrium moisture level, reduced sulfur content and increased heating value. The SynCoal product retains a majority of its volatile matter and demonstrates favorable ignition characteristics.

Although some difficulties have been encountered, SynCoal's technical and operating team are resolving the initial problems. The ACCP Demonstration program is continuing with a complete team effort involving all three of the major participants. It is expected that the ACCP demonstration will continue to produce test results over the next couple of years.


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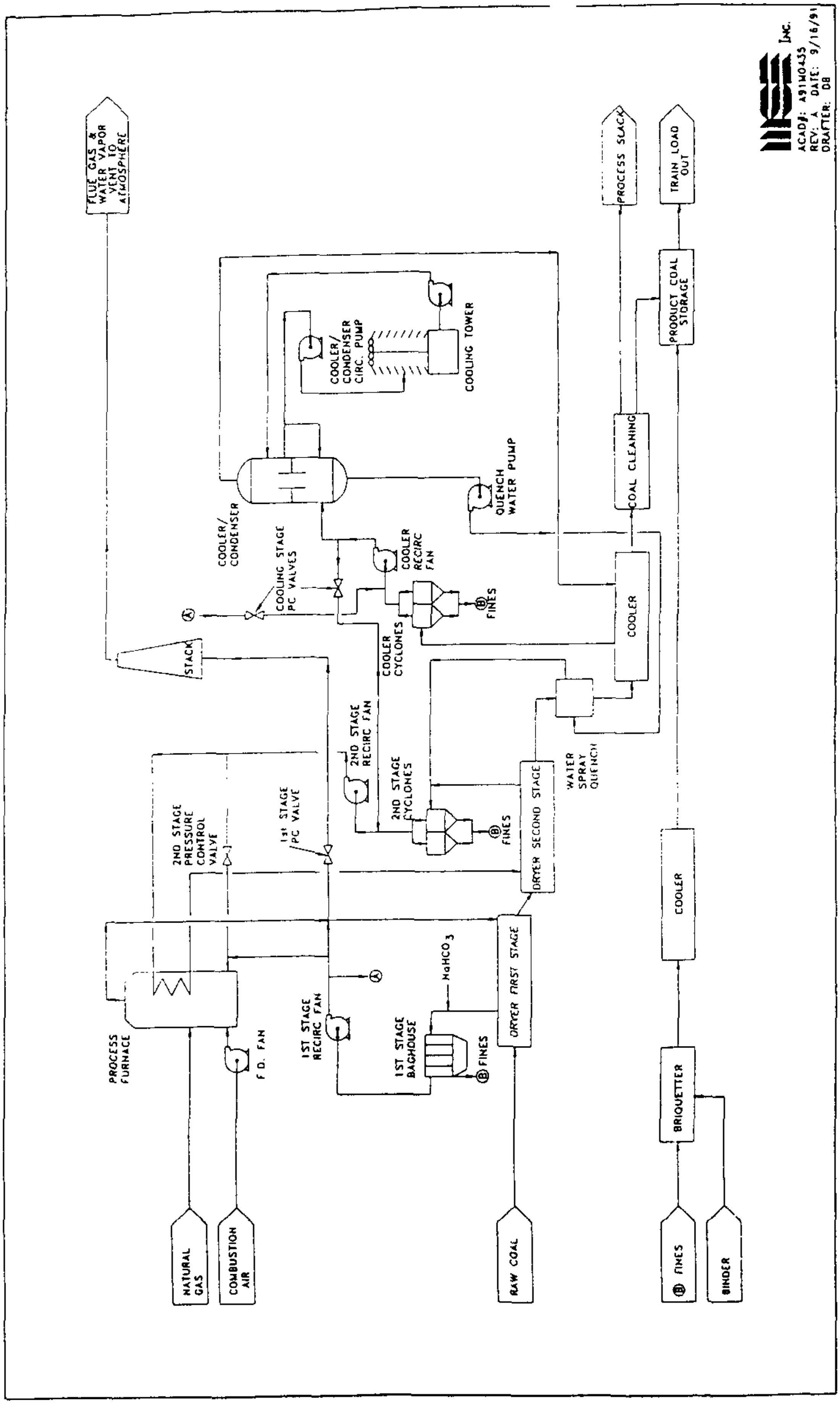
SynCoal™ is a registered trademark of the Rosebud SynCoal Partnership.

Figure 1


FLUE GAS & WATER VAPOR VENT TO ATMOSPHERE
PROCESS STACK
TRAIN LOAD OUT
ACAD#: A91M0435
REV: A DATE: 9/16/91
DRAFTER: DB
PRODUCT COAL STORAGE
COOLER/ CONDENSER CIRC. PUMP
COOLING TOWER
COAL CLEANING
QUENCH WATER PUMP
COOLER/ CONDENSER
COOLING STAGE PC VALVES
COOLER RECIRC FAN
FINES
COOLER
COOLER CYCLONES
STACK
2ND STAGE RECIRC FAN
2ND STAGE CYCLONES
WATER SPRAY QUENCH
DRYER SECOND STAGE
2ND STAGE PRESSURE CONTROL VALVE
1st STAGE PC VALVE
DRYER FIRST STAGE
PROCESS FURNACE
F.D. FAN
1ST STAGE RECIRC FAN
1ST STAGE BAGHOUSE
$NaHCO_3$
COOLER
BRIQUETTER
NATURAL GAS
COMBUSTION AIR
RAW COAL
FINES
BINDER
ROSEBUD SYNCOAL
ADVANCED COAL CONVERSION PROCESS
DEMONSTRATION PROJECT-PROCESS FLOW SCHEMATIC

## TABLE 1

## FEEDSTOCK AND SYNCOAL ANALYSES

**ROSEBUD MINE**

| Proximate Analysis | Rosebud Feedstock | MF* | SynCoal Product | MF* |
|---|---|---|---|---|
| % Moisture | 24.1 | -- | 1.0 | -- |
| % Volatile Matter | 27.4 | 36.1 | 37.6 | 38.0 |
| % Fixed Carbon | 37.1 | 48.9 | 51.6 | 52.0 |
| % Ash | 11.4 | 15.0 | 9.7 | 9.9 |
| BTU/lb. | 8,421 | -- | 11,832 | -- |
| % Increase in BTU/lb. | | | 40.51 | |
| **Ultimate Analysis** | | | | |
| % Carbon | 49.18 | | 67.71 | |
| % Hydrogen | 6.57 | | 5.20 | |
| % Oxygen | 30.99 | | 15.78 | |
| % Nitrogen | 0.69 | | 1.04 | |
| % Sulfur | 1.18 | | 0.48 | |
| % Organic Sulfur | 0.50 | | 0.40 | |
| **Petrographic Analysis** | | | | |
| % Huminite | 77 | | 81 | |
| % Exinite | 5 | | 2 | |
| % Inertinite | 18 | | 14 | |
| Reflectance | 0.42 | | 0.51** | |
| **Other Analysis** | | | | |
| Surface area ($cm^2/g$) | 288 | | 55** | |
| H/C Ratio | 1.60 | | 0.92* | |
| O/C Ratio | 0.24 | | 0.09* | |
| Apparent Aromaticity | 0.46 | | 0.66* | |
| % COOH | 0.74 | | 0.53* | |
| **Classification** | | | | |
| ASTM | Sub-bituminous C | | High-volatile bituminous C | |

* MF indicates moisture free proximate analysis of feedstock and Coal Product.
** Indicates increased coal rank of Coal Product.

# FUEL AND POWER COPRODUCTION THE INTEGRATED GASIFICATION/LIQUID PHASE METHANOL (LPMEOH™) DEMONSTRATION PROJECT

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## ABSTRACT

Under a pending Agreement, the U.S. Department of Energy (DOE) and Air Products and Chemicals, Inc., plans to locate one of the Nation's 42 "showcase" Clean Coal Technology projects in the State of California. An estimated total of $213.7 million in Federal and private funds will be invested to build and operate a highly advanced methanol production unit employing Air Products Liquid Phase Methanol (LPMEOH™) technology.

This first-of-a-kind demonstration -- one of 13 projects selected under the third round of the DOE's Clean Coal Technology Program -- will be associated with the Texaco Cool Water Integrated Coal Gasification Combined Cycle (IGCC) Power Project at Daggett, California. The LPMEOH Technology that will be used in the demonstration has been developed specifically to lower the cost of electricity produced in IGCC power plants by efficiently storing energy in the form of methanol for use during periods of peak power demand. In addition to cleanly generating electricity, the Texaco Cool Water Project will help California meet its solid waste reduction goals by using municipal sewage sludge along with coal as a gasifier feedstock. The project also will provide methanol for a variety of fuel-use demonstrations in the Los Angeles Basin area.

The LPMEOH technology development and demonstration will permit the Once-Through-Methanol (OTM) production concept to be added to the very clean and efficient IGCC power generation technique. The IGCC/OTM demonstration meets key objectives of the National Energy Strategy. The methanol can be used to provide peak electric power when needed, or as a clean liquid coproduct that will be in increasing demand as the Nation turns toward cleaner alternatives. Successful demonstration of the combined IGCC/OTM technologies at Cool Water will advance an environmentally clean, coal-based alternative to natural gas for power plants and helps contain or lower electricity prices.

## INTRODUCTION

This paper describes an advanced methanol production technology developed specifically to lower the cost of electricity produced in Integrated Coal Gasification Combined Cycle (IGCC) electric power plants. The technology is called the Liquid Phase Methanol (LPMEOH) process. The technology is used in a Once-Through-Methanol (OTM) configuration, a concept in which carbon monoxide (CO)-rich coal gas is directly and simply converted to methanol. The IGCC/OTM concept efficiently stores energy in the form of methanol -- cleanly derived from coal via gasification and conversion -- for use during periods of peak electric power demand. There are unusual efficiency and cost benefits realized with this type of energy storage, because of the fundamental fit of the OTM coproduction concept with the IGCC process. Unique power production load-following flexibility, not normally associated with coal-based power production plants, is available using IGCC/OTM.

Methanol can be substituted for conventional fuels in stationary and mobile combustion applications. In particular, methanol can serve as an excellent peaking fuel. Methanol contains no sulfur and has exceptionally low nitrogen oxides ($NO_X$) characteristics when burned. In fact $NO_X$ emissions when methanol is burned as a fuel is substantially less than those of distillate oil fuel, and can be as much as 50% less than emissions from natural gas fired combustors. This is because methanol burns with a lower flame temperature than distillate oil or natural gas.

Methanol has been tested successfully as a gas turbine fuel [1,2,3,4]. In the tests conducted by both Florida Power Corporation and Southern California Edison Company, methanol burned in 26 MW gas turbine units showed the following:

1) Modest system modification requirements;
2) Improvements in heat rates of 1 to 2%;
3) Reduced $NO_X$ emissions when compared to both distillate oil or natural gas; and
4) Cleaner gas turbine components (indicated by hot end inspections).

Despite these technical virtues, methanol has not yet been embraced as a substitute fuel. If fuel methanol could be economically produced from coal, the commercialization hurdle could be surmounted. This demonstration at Cool Water will show that methanol can be produced as a coproduct in an IGCC facility producing electric power. Coproduced methanol provides a cost competitive electric peak load energy storage system. This competitive edge is primarily due to the synergism between the IGCC and the OTM processes using the LPMEOH technology. The OTM process is a flexibility-enhancing add-on feature to IGCC electric power plants, with methanol being produced and stored during off-peak power demand periods, and used to provide backup fuel and peaking fuel during peak power demand periods.

## THE OTM CONCEPT AND LPMEOH TECHNOLOGY DEVELOPMENT

The IGCC power process is an advanced clean coal technology with high thermal efficiency, superior environmental performance, and the ability to handle all coals (from lignite to high-ranked bituminous) and other (waste) hydrocarbon feedstocks. The Department of Energy states [5], "IGCC plants are viewed as superior to today's conventional coal plants and are almost certain to be one of the lowest cost fossil fuel sources of electric power generation in the 21st century. Compared to today's conventional coal burning methods, an IGCC plant can produce up to 25 percent more electricity from a given amount of coal. Air pollutants can also be removed more efficiently from gas produced in a pressurized IGCC system than from the flue gas which results when coal is burned directly." Integrated coal/waste gasification power plants are more efficient and cleaner than direct coal/waste combustion power plants. Integrated gasification also has the advantage of providing a replacement for natural gas in existing natural gas-fired combustion turbines, including cogeneration systems. Therefore, integrated gasification can be effective for hedging the risk of uncertain natural gas prices in the short term, and for replacing natural gas in the long term.

Air Products has had a continuing interest in and involvement with coal gasification, since this process requires oxygen and produces hydrogen. Coal gasification has had a substantive history in providing the 19th and 20th Century's industrialized world with fuel gas, chemicals, liquid fuels, and transportation fuels. Gasification technologies have continued to evolve and improve.

In the 1970's and 1980's the new high pressure oxygen blown coal gasifier technology was combined with the new combined cycle power plant technology to create the advanced IGCC power plant concept. The concept was first demonstrated at the 100 MW IGCC power plant demonstration at Cool Water from 1984 to 1989.

With the IGCC power process, the coal is gasified with oxygen under pressure, heat is recovered from the resultant fuel gas, the fuel gas purified, and the clean fuel gas fed to the combined cycle power plant gas turbines (Exhibit 1). The fuel gas consists mainly of hydrogen ($H_2$), CO, and some carbon dioxide ($CO_2$). Because coal gasification produces $H_2$ and CO; i.e., synthesis gas (syngas), methanol coproduction is a natural opportunity (Exhibit 2). It was this opportunity that attracted Air Products to develop the OTM concept based on the LPMEOH Technology. In particular, we were encouraged by the Electric Power Research Institute (EPRI) who had studied IGCC characteristics and electric utility requirements, and concluded that coproduction of methanol to provide energy storage had commercial potential. Subsequently, DOE became a major sponsor and, along with EPRI, nurtured the development efforts.

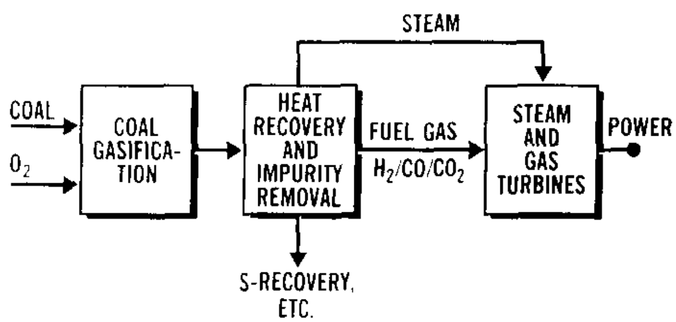


**Exhibit 1. Electric Power by Integrated Coal Gasification Combined-Cycle (IGCC)**

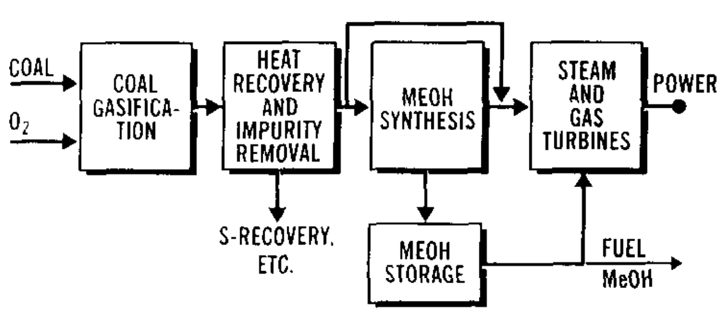


**Exhibit 2. Coproduction of Power and Methanol via IGCC**

There were two methanol coproduction options to be considered for development: conventional recycle methanol technology or the OTM concept (Exhibit 3). The OTM concept provided a better fundamental approach to fitting the requirements of the IGCC application, and was selected for development. The ideal methanol technology for IGCC/OTM applications must be able to directly process CO-rich gases produced by advanced coal gasifiers. Usually the CO concentration is high and the $H_2$ to CO ratio is low. $CO_2$ content is variable depending on the type of coal feeding system; i.e., dry coal or slurry. The ability of the methanol process to load-follow is key -- that is on a daily basis to start quickly, stop, and ramp rapidly. Finally, the process should be relatively simple and reliable, adding value to the IGCC operation, not detracting in any way from the high reliability expected on the IGCC installation. Conceptually the OTM synthesis step can be simply inserted in the IGCC flowsheet (Exhibit 4). In a OTM arrangement, a fraction of the fuel gas is converted to methanol, typically between 10% and 40% of the heating value. In an electric power cycling scenario, methanol is produced during low demand periods and accumulates in storage; during peak demand it is withdrawn and burned as peaking fuel. The front-end coal gasification section runs full-out all of the time.

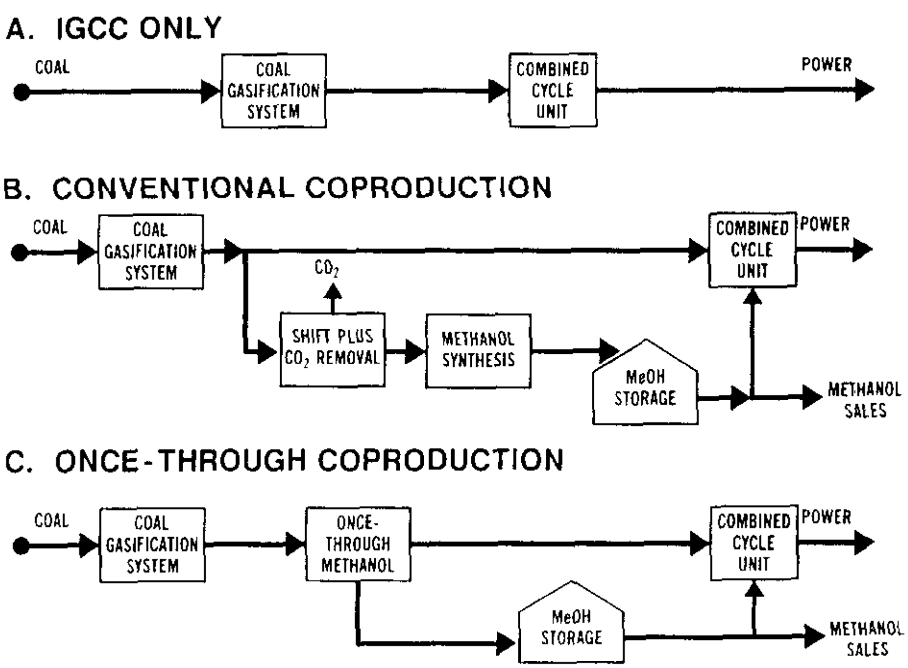


**Exhibit 3. Options for Methanol Coproduction in Gasification Combined Cycle Power Plants**

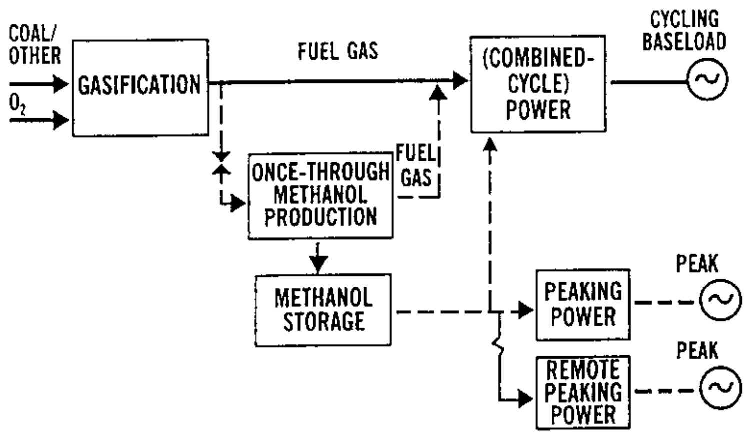


**Exhibit 4. IGCC/OTM Power with Energy Storage**

The fundamental characteristics of a liquid phase reactor, which is used in the LPMEOH technology, make it particularly suitable for these OTM needs. It is unlike the conventional gas phase reactors that use fixed beds of catalyst pellets and largely depend upon recycle diluent gas to both dilute the CO concentration and control the reaction exotherm. The LPMEOH reactor is a slurry reactor. The catalyst particles are very small, powder-size, and are suspended in an inert oil, a mineral oil. The synthesis gas bubbles up through the slurry. The $H_2$ and CO dissolve in the oil and diffuse to the catalyst surface where the methanol reaction occurs. The product methanol diffuses out and exits with the unreacted syngas. The inert oil acts as a heat sink and permits isothermal operation. The net heat of reaction is removed via an internal heat exchanger which raises steam. Unlike the gas phase reactors that limit the per-pass conversion to methanol to accommodate the reaction exotherm, the LPMEOH reactor meets the reaction exotherm head-on and maintains isothermal operation. And unlike the gas phase reactors, the LPMEOH reactor is tolerant to CO-rich gas. It does not require recycle. Shift and $CO_2$ removal are not required. Low $H_2$-to-CO ratios are acceptable -- and so also is any $CO_2$ content. Finally, in contrast to the gas phase reactor in which the catalyst is sensitive to flow variations and changes from steady-state, the LPMEOH reactor is eminently suited for load-following.

Work on the development of the LPMEOH technology began in 1981, with a DOE contract to prove the concept at a small but representative engineering scale [6]. A pilot plant was constructed at Air Products' synthesis gas facility at LaPorte, Texas and nameplated at 5 TPD (Exhibit 5). In the final operating campaign concluded in 1989, we successfully tested the unit with very aggressive operating conditions [7]. Summarizing the results from LaPorte: We accumulated 7400 hours of synthesis operation, most on CO-rich gas. We achieved good catalyst life, and pushed catalyst concentration and methanol production rates well beyond original expectations. The LPMEOH reactor proved to have impressive start, stop, and ramping abilities. And while this is a test unit and LPMEOH is a pioneer technology, we achieved a 99%+ on-stream factor.

## COMMERCIAL DEMONSTRATION OF THE LPMEOH PROCESS

The success of the LaPorte pilot plant operation, as well as the reactor modeling efforts and the broad laboratory testing base, has established a sufficient data base to allow for a confident move to the next scale of operation. The next step for LPMEOH technology is demonstration at commercial scale using coal-derived synthesis gas. Round III of the DOE Clean Coal Technology Program, provided the opportunity for the LPMEOH technology to make the move to the commercial scale. In response, Air Products proposed to design, construct, and operate a demonstration LPMEOH plant at a coal gasification facility. In December 1989, the DOE selected this proposal for negotiation.

Following months of negotiation, the initial coal gasification host site was no longer available to serve for the LPMEOH demonstration project. Air Products later announced plans to work with Texaco Syngas, Inc., to relocate the LPMEOH demonstration project to the Cool Water Coal Gasification Plant located in Daggett, California. The scale of the LPMEOH demonstration facility will be 150 tons-per-day of methanol. The project includes design, construction, and 4 years of test operation of the LPMEOH unit, as well as 3 years of fuel-grade methanol user tests. Start-up is planned for 1995. Air Products has signed the cooperative agreement, and the DOE forwarded the project's Comprehensive Report to Congress on 11 August 1992. Award of the cooperative agreement will follow a 30, in session day congressional review period.

### Cool Water IGCC Facility Site

The advanced IGCC power plant concept was first demonstrated at the 100 MW Cool Water facility located at Southern California Edison's station at Daggett, California, from 1984 to 1989 using the slurry-fed oxygen-blown Texaco Coal Gasification process. The successful demonstration at the Cool Water IGCC facility made it recognized as an important large scale research and development center, uniquely suited to carry out advanced IGCC development, and development of associated technologies. At 1/3 to 1/2 of a commercial IGCC plant size, Cool Water is ideal for development and demonstration at reasonable costs. The Daggett site combines easy access to a major metropolitan area with a remote testing location (Exhibit 6).

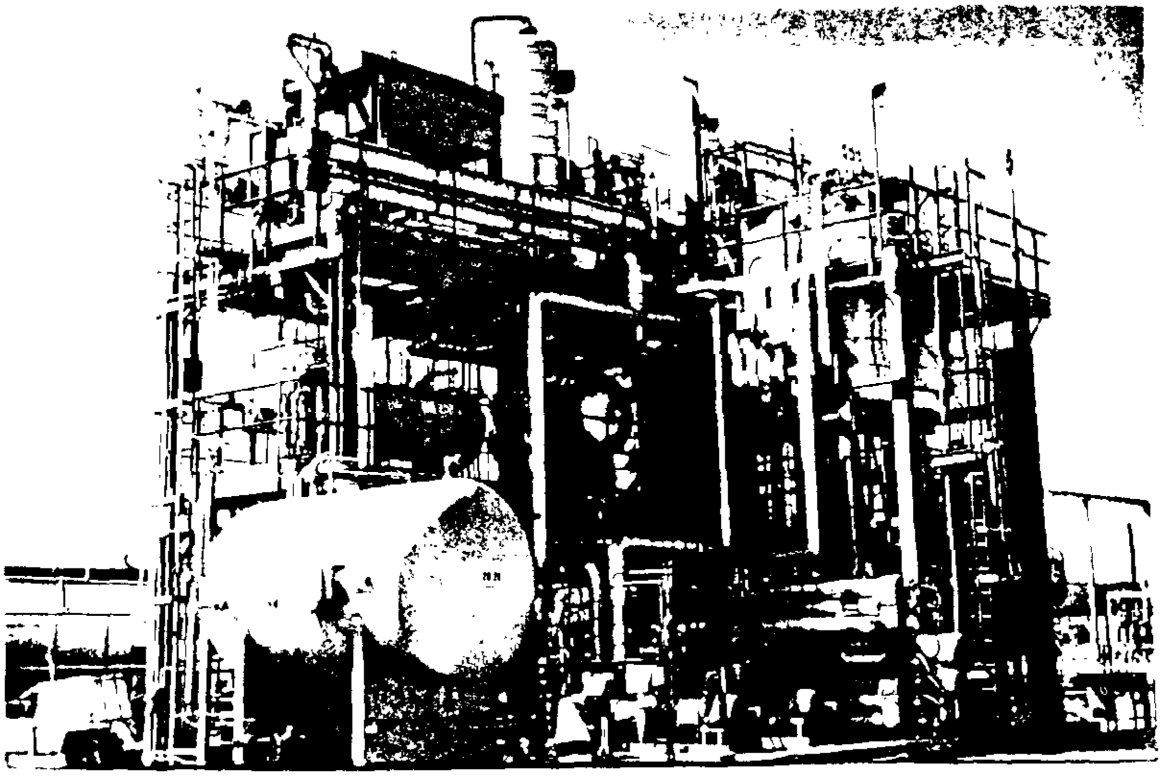

**Exhibit 5. Liquid Phase Methanol Pilot Plant at LaPorte, Texas**

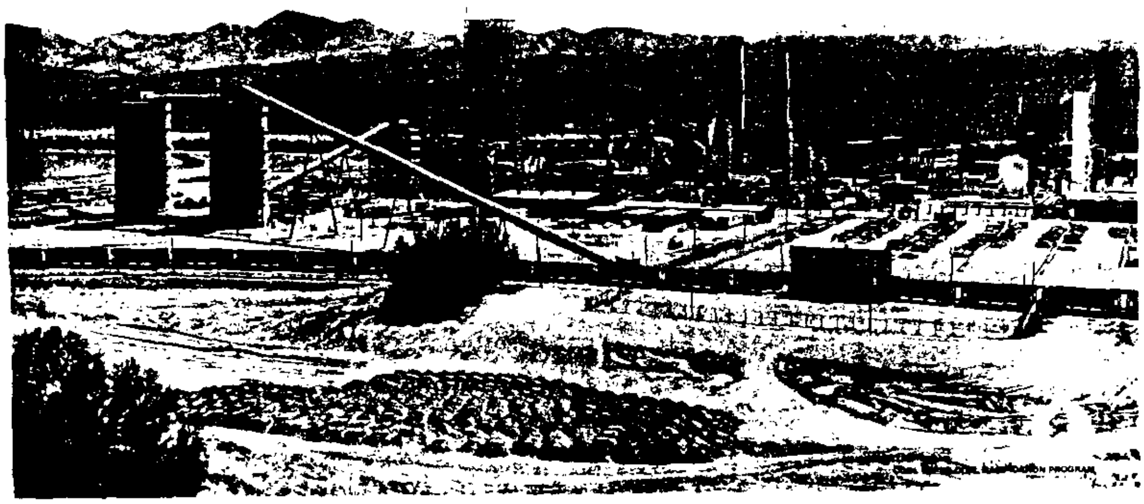

**Exhibit 6. Cool Water Coal Gasification Power Plant, near Daggett, California**

The Cool Water IGCC facility is presently an unemployed asset. Texaco proposes to acquire the facility from Southern California Edison, to upgrade it to meet new environmental standards, and to operate it to develop and demonstrate improvements to IGCC technologies. Two important IGCC enhancements will be demonstrated initially as part of the Texaco Cool Water Project:

- Destruction of municipal sewage sludge in an environmentally superior manner by gasification of the sludge with coal to produce a clean synthesis gas, and

- Using the clean synthesis gas to coproduce methanol and electric power, demonstrating the Once-Through Methanol process employing the LPMEOH technology.

The California Energy Commission (CEC) has identified these IGCC advancements as a California Research, Development and Demonstration goal.

Texaco is in the final stages of negotiations for purchasing the Cool Water Coal Gasification Power Plant from Southern California Edison. The operating permits are being amended through the CEC to allow continuing demonstration of the technology with incorporation of the gasification of sewage sludge, the production of methanol and other refinements. The facility has received it's Qualifying Facility (QF) certification from the Federal Energy Regulatory Commission (FERC) and Research, Development and Demonstration (RD&D) designation from the CEC. Texaco must complete negotiations for the sale of power that will be generated, and receive approvals from the CEC and the California Public Utilities Commission. Construction will commence after these approvals and receipt of the CEC Certification, with operation planned for 1995.

The Cool Water Integrated Gasification demonstration project is an important part of the DOE's Clean Coal Technology IGCC demonstration programs. The DOE plans to help demonstrate several IGCC systems as part of the Clean Coal Technology (CCT) program [5] in order to provide "a wide matrix of conditions for evaluation of future commercial projects. The projects range in size from 55 to 265 MWe capacity and include synthesis and combustion of methanol as a load balancing alternate." There are multiple technology suppliers and multiple operating (demonstration) facilities in order to provide a sound basis for evaluation and acceptance by the Electric Utility industry. The point of each demonstration is to advance the availability, acceptance, and penetration of IGCC and related technologies. Advancements of IGCC technologies are likely to lower electricity prices, and more importantly will promote an environmentally clean coal-based alternative to natural gas.

DOE plans to provide 43 percent, over $90 million, of the funding for the technology demonstration. The remainder of the funding comes from the private industry participates, and from revenues generated by the sale of the produced methanol. This demonstration meets DOE goals to advance IGCC commercialization, by providing: a) energy storage for electric load-following; b) distributed load capability, i.e., clean methanol distributed to small use point power plant sites (Exhibit 4); and c) clean liquid fuel from coal and sludge wastes. Additional IGCC advancement benefits, which will result from the initial operation of the Texaco Cool Water Project, include low $NO_x$ burner technology, gasifier slag beneficial uses, and sulfur and carbon dioxide recovery and commercial use. Proximity to Los Angeles means that a wide variety of sludge waste oil and other feedstocks are available in quantity, and California offers a wide range of suppliers of advanced energy technologies, such as fuel cells. Long term benefits could include demonstrations of gasification of other wastes, coproduction of other once-through liquid fuel products (a DOE R&D objective, Ref. 8), and testing of the coproducts in advanced power production technologies such as fuel cells for electricity and/or transportation.

Details of the DOE Cooperative Agreement

Although it caused a delay in project initiation, the move to the new host site at Cool Water is advantageous. At this site, the LPMEOH technology will be demonstrated in its commercial configuration -- as an integrated IGCC/OTM facility that produces methanol on a once-through basis for use as a turbine peaking fuel within the IGCC power plant or as an export for commercial sale. During peak electric demand periods, the syngas produced by the facility will be used to generate electricity. During off-peak demand periods, about 15% of the syngas will be diverted from the power plant's turbines to produce methanol. A portion of the methanol will be stored to provide additional fuel to the electric power plant during peaking hours. The remainder will be available for California's market needs.

The specific objectives of the LPMEOH technology demonstration include the following:

- To achieve long-term operation of the LPMEOH facility on synthesis gas produced by coal gasification;

- To demonstrate the cost effectiveness of the LPMEOH technology in a commercial embodiment, IGCC/OTM;

- To demonstrate the quality of the methanol product by user tests in transportation, boiler, and combustion turbine applications;

- To demonstrate scale-up of the LPMEOH slurry reactor fluid dynamics.

## APPLICATIONS -- ENERGY STORAGE FOR ELECTRIC POWER PRODUCTION

Now -- shifting to the commercial application -- we can review how OTM coproduction can enhance the economics and flexibility of power production. There are a number of ways. The OTM process can be used for energy storage, operating in the traditional sense to convert off-peak energy into high-value peak energy. Conventional energy storage technologies -- such as pumped hydroelectric, compressed air, and battery -- are generally known for their ability to provide economic and strategic benefits to electric utilities (Exhibit 7). All of these technologies take excess electric power from base-load generating units, store it, and deliver power during peak demand periods. The IGCC/OTM energy storage concept provides the opportunity to design energy storage into load-following coal-based power plants. The OTM process can also be used to coproduce backup fuel for base-load power plants, which can be used to increase the power plant on-stream time. Examples on how IGCC/OTM can directly enhance coal-based electric power production follow:

| CONCEPT | DUTY CYCLE | HOURS OF STORAGE | MODULE MW |
|---|---|---|---|
| PUMPED HYDRO | "BASELOAD" | 10 | 500-1500 |
| COMPRESSED AIR | INTERMEDIATE/ BASELOAD | 10 | 110-220 |
| BATTERY | PEAKING | 3 | 10 |
| IGCC/OTM | INTERMEDIATE/ BASELOAD | 4 - 10 | 100-600 |

**Exhibit 7. Conventional Energy Storage Concepts**

1. Load-Following Coal-Based Power Plants

New power plant capacity additions, when added to diversified utility systems, must dispatch effectively. The impact of a new IGCC/OTM power plant on a typical power pool (Exhibit 8) can provide great operating and dispatch flexibility for the utility. Examples of the flexibility a moderate size OTM plant (2.0 ton-per-day of methanol per net MW of base load power) can provide to a utility system is shown in Exhibits 9 and 10. Peak to valley power production ratios greater than two can be easily provided; while allowing the capital intensive gasifier to operate effectively at 100% load. The peaking power plant can be located on-site or remotely, since methanol is easily stored and transported.

Studies [9,10] have shown capital savings (smaller gasifier) and operating efficiencies can provide an electricity cost advantage approaching 10% for an IGCC/OTM energy storage power plant, relative to load-following with an IGCC power plant.

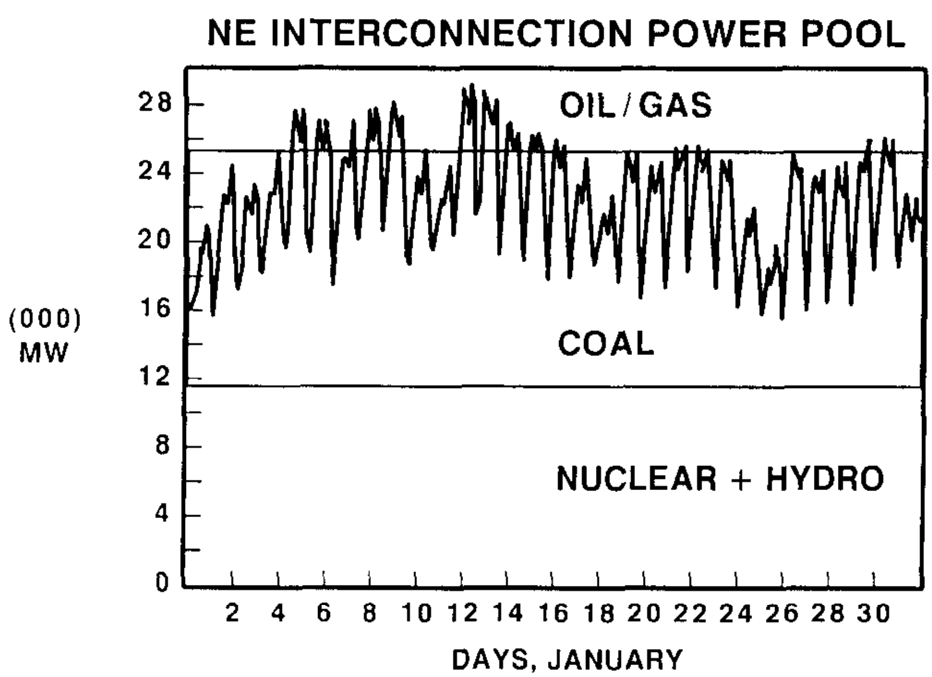


**Exhibit 8. Monthly Load Curve - Winter/NE U.S.**

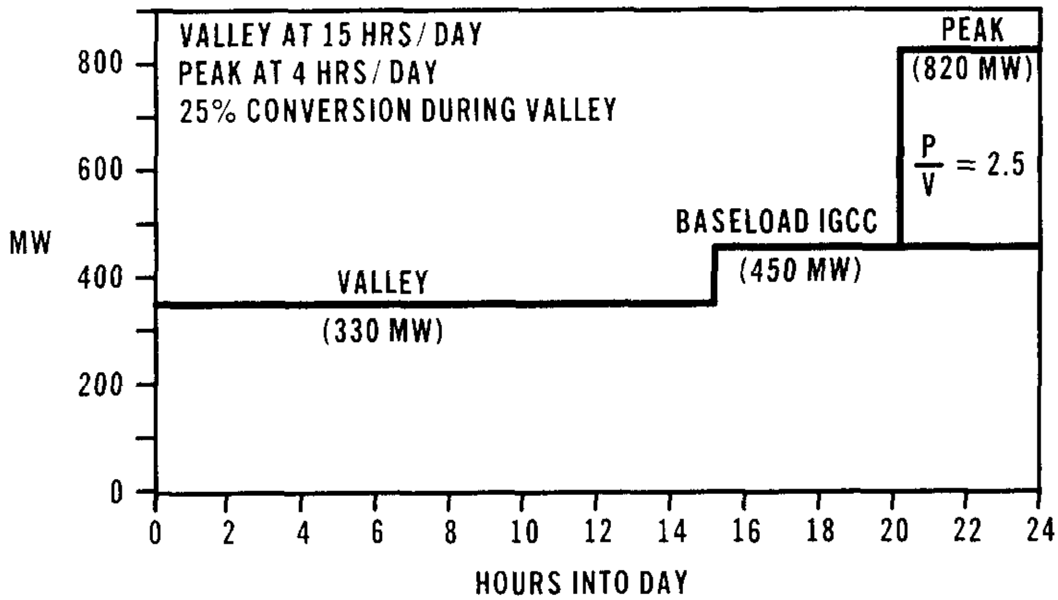


**Exhibit 9. Example IGCC with OTM Energy Storage**

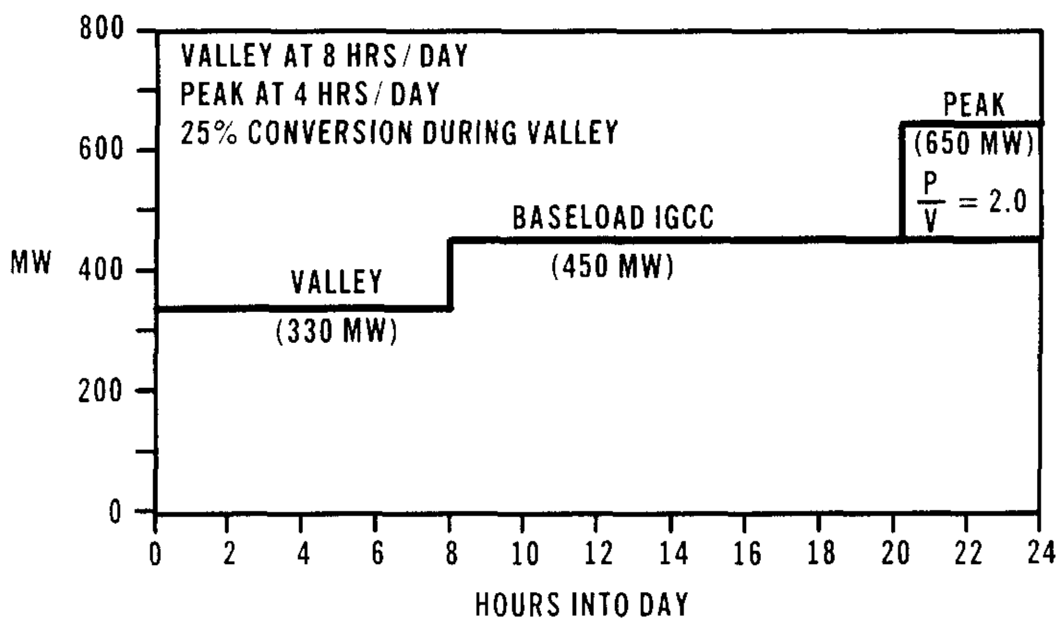


**Exhibit 10. Another Example**

2. Base-Load Power Plants

For base-load power plants, one study [11] compared an IGCC power plant with no spare gasifiers to an IGCC power plant with one 'spare' gasifier plus an OTM plant. The IGCC/OTM plant configuration increased the power plant equivalent availability from 86% to 93%. The methanol coproduction and the increased net power production off-set the cost of the spare gasifier and the OTM plant. The methanol plant investment was only 4% of the total plant investment. The IGCC/OTM plant design included the same number of gas turbines, and was developed for actual dispatched utility operation. At peak capacity, the levelized cost of electricity for the IGCC/OTM case was estimated to be one mill per kwh lower than that for the IGCC case, and the savings were even greater over the range of plant turndown.

The benefits of this IGCC/OTM coproduction scheme for base-load power were found to include:

- Unscheduled gasifier outages - syngas to the methanol plant can be immediately diverted to the power block; (e.g., the backup fuel is syngas) since the LPMEOH technology provides instant shutdown and fast restart capability of the OTM plant.

- Planned gasifier train shutdowns - stored methanol can be used effectively for the power block when syngas is not available, since the gasification train has to be shutdown for a longer period of time than the power block for planned maintenance.

- The methanol produced and stored, can also help reduce the risk of lower than expected gasifier availability. If in any year the gasifier component availability should decrease from 96% (the design basis) to as low as 84% (unlikely event), sufficient methanol would be available to maintain the power block operation at its 93% plant equivalent availability.

This interesting base load IGCC power plant study showed that a small (0.7 tons-per-day of methanol per MW net power) OTM plant can provide operating flexibility and reduce the cost of electricity from base-load IGCC facilities. It would be interesting for a future study to marry the base-load spare gasifier/OTM concept with the load-following peak power IGCC/OTM concept.

## CONCLUSION

The LPMEOH technology was primarily developed to allow OTM plant capability to be added to IGCC power plants to help reduce electricity costs and to improve the flexibility of electric power production. When incorporated in an IGCC power plant, the IGCC/OTM process provides energy storage and clean coproduct capability in the form of methanol, using the Nation's abundant coal reserves. The zero emission of sulfur and the low emissions of $NO_x$ when burning methanol make it attractive for industrial boilers, combustion turbines, fuel cells, and transportation vehicles.

The commercialization of the LPMEOH technology requires a comprehensive data base that demonstrates the performance, reliability, emission control capabilities, and cost effectiveness of the technology. This demonstration conducted under the Clean Coal Technology Program will test all operational phases of the LPMEOH technology that are anticipated to be encountered in commercial-scale facilities. The demonstration of the LPMEOH process at the Texaco Cool Water Project is consistent with the objectives of the Clean Coal Technology Program and provides an excellent mean to fulfill the goals of the National Energy Strategy.

To summarize, LPMEOH technology provides an energy storage concept specifically for IGCC power plants. LPMEOH process is simple, efficient, and reliable. The LPMEOH technology can be readily deployed in the future as an OTM add-on to IGCC facilities. For a relatively modest investment, OTM greatly enhances the operational flexibility of a IGCC facility. Beyond traditional energy storage ability, IGCC/OTM can provide back up and transportable peaking fuel from base load feedstock. The technology has performed well at the pilot scale and is now advancing toward the demonstration scale via the Clean Coal Technology III Program.

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# SESSION 6:
# Advanced Combustion/Coal Processing

*Chairs: Dennis N. Smith, DOE PETC*
*George E. Lynch, DOE Headquarters*

**An Air Cooled Slagging Combustor with Internal Sulfur, Nitrogen, and Ash Control for Coal and High Ash Fuels**, Dr. Bert Zauderer, President, Coal Tech Corporation. Co-authors: E.S. Fleming and B. Borok, Coal Tech Corporation.

**The Healy Clean Coal Project**, Steve M. Rosendahl, Project Manager, Stone & Webster Engineering Corporation, and Dennis V. McCrohan, Alaska Industrial Development and Export Authority

**Demonstration of PulseEnhanced™ Steam Reforming in an Application for Gasification of Coal**, Richard E. Kazares, Vice President, Sales and Applications Engineering. Co-authors: William G. Steedman, Senior Systems Engineer, ThermoChem, Inc., and Dr. Momtaz N. Mansour, President, MTCI, Inc.

**Coal Quality Expert: Status and Software Specifications**, Clark D. Harrison, President, CQ, Inc.

**Self Scrubbing Coal: An Integrated Approach to Clean Air**, Robin L. Godfrey, Executive Vice President, Custom Coals Corporation

# AN AIR COOLED SLAGGING COMBUSTOR WITH INTERNAL SULFUR, NITROGEN, AND ASH CONTROL FOR COAL AND HIGH ASH FUELS

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## ABSTRACT

This paper describes the results of a 5 year test effort on a 20 MMBtu/hr slagging, coal combustor that was retrofitted to an oil designed package boiler. The initial phase of this effort from 1987 to 1990 was sponsored in part by the DOE Clean Coal Program, the State of Pennsylvania, and private sector concerns. In the past two years additional testing was sponsored by the DOE SBIR program and industrial clients. The combustor has operated a total of about 1300 hours on oil, gas, and dry pulverized coal. In the past two years combustor tests on coal fly ash vitrification, and co-firing of coal with municipal refuse derived fuels have been completed.

A major focus of the combustor test effort has been on environmental control in coals with sulfur contents ranging from 1% to 3.3%. With staged combustion, the NOx emissions were reduced by about two-thirds to less than 200 ppm, with further reductions to 140 ppm in the stack particle scrubber. Injection of various calcium based sorbents into the combustor yielded continuously higher SO2 reductions as measured at the boiler outlet, i.e. at the base of the stack. In recent tests 90 to 95% SO2 reductions were measured. The 15 year levelized cost of retrofitting a 250 MW power plants with this technology is \$343/ton of SO2 and NOx, with 2.4% sulfur coal. For 4.3% sulfur coal, the cost is \$225/ton. The capital cost is \$229/kW.

Current test efforts are focused on the application of the combustor to industrial combined gas-steam turbine power plants in the 5 to 20 MW range, where its use may offer significant performance and cost advantages. As part of this effort, additional tests on combustor durability, automatic computer control, and optimum environmental performance are in progress.

## INTRODUCTION

This paper summarizes recent results of Coal Tech's commercial scale demonstration of a patented air cooled, slagging coal combustor. Air cooling results in a high thermal efficiency SO2 and NOx emissions are controlled inside the combustor. The combustor is designed for new and retrofit boiler applications. The air cooled combustor development began in the late 1970's using a 1 MMBtu/hr air cooled cyclone combustor[1]. Development continued in the mid 1980's with SO2 and NOx control tests in a 7 MMBtu/hr water cooled cyclone combustor[2]. This work was followed by the design, construction, and installation of the present 20 MMBtu/hr, air cooled, combustor between 1984 and 1987 [3]. In 1987 the combustor was tested initially with coal water slurry fuels, and then converted to pulverized coal operation.

The first 3 years of the demonstration effort were conducted under the DOE Clean Coal Program sponsorship. During the Clean Coal project, which began in 1987, many of the operational issues involved in using an air cooled combustor were resolved. By the end of the Clean Coal project, nearly 800 hours of combustor operation as part of the Clean Coal project and 100 hours under other projects, were completed. About 1/3 of the test hours were on coal. A significant number of these tests consisted of four day, round the clock operation, with daytime firing on coal and overnight automatic pilot gas firing.

Since the completion of the Clean Coal tests, the combustor has been used on other test projects. Tests were conducted on ash vitrification[10] and refuse derived fuel combustion[15]. During these tests, the data base developed during the manually controlled Clean Coal project tests was used to automate the combustor's operation. For this purpose, a process control software was specialized for the combustor's operation and installed on a micro-computer. In addition, major progress was made on improving the combustion efficiency and the SO2 reductions.

Current test efforts focus on round-the-clock, coal fired operation under automatic computer control. The objective is to acquire a data base on durability of combustor components. Another focus is to remove essentially all (i.e. 100%) of the coal sulfur in the combustor. Finally, the application of the combustion to combined cycle, industrial power plants is being investigated as the first commercial use of this technology.

Progress reports on the air cooled combustor tests were presented at the 5th Annual Pittsburgh Coal Conference[4] in September 1988, the 82nd Air Pollution Conference[5] in June 1989, and the 7th Annual Pittsburgh Coal Conference in September, 1990[6]. The economics of emission control in utility boilers with this combustor were first presented in March 1990[7]. The Clean Coal Final Report, which was published in November 1990, contains a detailed description of the Clean Coal Project[8]. It is available from either National Technical Information Service or Coal Tech.

Coal Tech's Advanced Air Cooled, Cyclone Coal Combustor

The cyclone combustor is a high temperature ( > 3000 F) device in which a high velocity swirling gas is used to burn crushed or pulverized coal. The ash is separated from the coal in liquid form on the cyclone combustor walls, from which it flows by gravity toward a port located at the downstream end of the device. A brief description of the operation of Coal Tech's patented, air cooled combustor is as follows (see Figure 1): A gas and oil burner, located at the center of the closed end of the unit, is used as a pilot to pre-heat the combustor and boiler during startup. Dry pulverized coal and limestone powder for SO2 control are injected into the combustor in an annular region enclosing the gas/oil burners. Air cooling is accomplished by using a ceramic liner, which is cooled by the swirling secondary air. The liner is maintained at a temperature high enough to keep the slag in a liquid, free flowing state. The liquid slag is drained through a tap located at the downstream end of the combustor.

Nitrogen oxide emissions are reduced by operating the combustor fuel rich. Between 67% and 80% NOx reductions were measured in pilot combustors rated at 1 MMBtu/hr[9] and at 7 MMBtu/hr[10]. In the 20 MMBtu/hr combustor, about two-thirds stack NOx reductions to less than 200 ppm (normalized to 3 % O2) have been measured under staged combustion operation.

A major focus in the air cooled combustor's development was the control of sulfur emissions by means of Coal Tech's patented, limestone injection process into the combustor. The process is based on non-equilibrium chemical capture of the sulfur by the sorbent particles, and retention of the reacted sorbent in the slag. The slag is removed from the combustor before the sulfur can re-evolve as a gas. Previous results obtained in the 7 MMBtu/hr combustor tests[10] yielded SO2 reductions approaching 100% [measured at the stack exhaust] with limestone injection in the first stage. After extensive testing during the past 5 years, this SO2 result has been recently duplicated in the present 20 MMBtu/hr combustor. Due to the complexity of this process, this new result will require extensive confirmation testing.

Description of the 20 MMBtu/hr Combustor-Boiler Test Facility

The design of the 20 MMBtu/hr Coal Tech combustor was based on a detailed design of an air cooled combustor at thermal input ratings of 100 MMBtu/hr.[11] The 20 MMBtu/hr combustor was installed on a 17,500 lb/hr steam boiler in an industrial plant in Williamsport, PA in early 1987. Figure 2 shows a side view drawing of the combustor attached to the boiler.

The coal is pulverized off-site, and it is delivered to the site in a tanker truck. A 4 ton capacity coal storage bin next to the boiler house receives the powdered coal from the tanker. The coal is metered through a pneumatic line to the combustor. The bin is refilled without combustor shutdown. The combustor's slag retention is inadequate to meet local particulate emission standards. Therefore, a wet particulate scrubber located on the roof of the boiler house removes particulates. Slag drains from the combustor through an opening at the downstream end of the combustor (See figures 1 and 2) into a water filled tank. The slag is removed from the tank by means of a mechanical conveyor belt and deposited in a drum located next to the slag quench tank. The fuel and air streams to the combustor are computer controlled using the combustor's thermal performance as input variables. In the Clean Coal project, these functions were performed manually. Diagnostics consist of measurement of fuel, air and cooling water flows, combustor wall temperatures, and stack gas measurements, including $O_2$, $CO_2$, CO, $SO_2$, $NO_x$, HC. Gas samples are taken in the stack above the boiler and in the exhaust from the wet scrubber.

## TEST RESULTS

### Test Activities Dealing with the Combustor's Operation

One of the important results of the Clean Coal project was the development of an operational data base for the air cooled combustor-boiler system. Problems resolved included materials durability, slag tap blockage, overheating of the boiler-combustor interface , defects in commercial auxiliary components, and coal feed non-uniformities. This work is described in detail in the Clean Coal final project report[8].

To illustrate the nature of the operational data on the combustor, this paper will discus briefly three operational issues that are critical for proper slagging combustor operation. They are: Coal feed and air-fuel mixing, slag retention, and automatic control of the combustor.

#### (i) Solids Feeding & Air-Fuel Mixing

Uniform solids feeding and air fuel mixing are very critical to proper combustor operation, especially under fuel rich conditions. Variability in solids flow causes combustion fluctuations of both long duration (several minutes) and short duration (several seconds). Both fluctuations must be eliminated for proper combustion and environmental performance. After numerous trials and error methods, this problem was completely solved about 1-1/2 years ago by rearranging the pneumatic lines and damping the feed rates. Feed fluctuations were reduced from as high as 17% in early tests to less than 1% currently.

(ii). Slag Retention

Slag retention in the combustor is a function of combustor stoichiometry, combustion efficiency, coal slagging properties, combustor swirl pressure, total slag flow rate, and combustor geometry. For example, initial testing in high viscosity coal ashes, which yielded poor combustion efficiency, also resulted in low slag retention. To correct this problem, limestone (LS) injection was routinely used to flux the ash of these coals. This improved both combustion efficiency and slag retention. Combustor stoichiometry is the most important of the slag retention parameters. Under fuel rich conditions in the combustor, retention is generally lower. Slag retention in the combustor and exit nozzle averaged 72%, with a range of 55% to 90%, for all conditions. Under near stoichiometric conditions, the average was 80%, with a range of 65% to 90%. These data are averaged over numerous tests, which include earlier tests under less than optimum operating conditions. As the combustor's operating history is extended, it is believed that retention in the 80% range can be consistently achieved. Analytical computer modeling studies are in progress to quantify the relationship between combustor operating conditions and slag retention.

(iii). Automated & Computer Controlled Combustor-Boiler Operation

During the Clean Coal project, the combustor's coal fired operation was controlled manually. By 1990, sufficient operational data had been accumulated to begin to convert the combustor to computer controlled operation. A commercial process control software was modified to control the combustor. During the past two years, this control system has been gradually improved and upgraded. The computer controls all fuel feeds, i.e. gas, oil, and coal, sorbent injection feed, the various control valves for the combustion air, and it monitors the combustor performance variables. At present, the computer control system is nearly completely developed. This system now operates the combustor, collects the tests data, and converts it to a readily analyzable form.

Environmental Performance

(i). NOx Emissions

In tests with staged combustion, NOx levels at the boiler outlet were reduced by > 60% from the unstaged, excess air (XSA) values. This corresponds to about 184 ppm, normalized to 3% oxygen, or 69 ppm at gas turbine outlet conditions, namely 15% oxygen. Figure 3 compares the NOx reduction of this combustor with that of the 1 MMBtu/hr units.

(ii). SO2 Emissions

In the Clean Coal project tests, at limestone injection rates in the combustor corresponding to Ca/S ratios ranging from 0 to 3, the maximum average reduction in measured SO2 at the boiler outlet was 35%. Injection of calcium hydrate, yielded in both the Clean Coal and subsequent tests before 1991, a maximum reduction of 54% +/-2% at an average Ca/S ratio of 1.95 measured at the boiler outlet.

Recently, after further major improvements in combustor performance were achieved, limestone injection yielded reductions of 56% at a Ca/S ratio of 2. Tests were recently initiated with calcium hydrate injection and SO2 reductions of 90 to 95% were measured. Tests to verify these results and extend them to 100% SO2 reduction are continuing. Figure 4 shows that these improved SO2 reduction are also a function of the operating conditions in the combustor.

A major objective of the sulfur capture tests was to maximize the sulfur retention in the slag removed from the combustor. In the absence of sorbent injection in the combustor and with efficient coal combustion, no sulfur reported to the slag. As the slag flow conditions improved, a maximum of 20% of the coal sulfur was recently measured in the slag. The balance of the captured sulfur is contained in dry ash and reacted sorbent that is deposited on the boiler floor or collected in the wet particle scrubber. It important to note that none of the sulfur capture data reported in this paper includes sulfur captured in the wet particle scrubber. All the SO2 gas measurements reported here were obtained at the boiler outlet, at a distance of about 40 feet upstream of the wet particle scrubber. The latter did contribute to the sulfur capture. However, these results are of no interest to the combustor technology, and they are not discussed here. They can be found in the Clean Coal Final Report[8].

A second method of achieving SO2 reductions is to inject sorbent into the boiler, downstream of the combustor. Using calcium hydrate, this method yielded up to 80% SO2 reductions at the boiler outlet. In this case, no sorbent was injected in the combustor.

Solid Waste Disposal

Compliance testing was performed on the slag solid waste, as per regulations of the Pennsylvania Department of Environmental Regulation (PA-DER) Bureau of Solid Waste. Slag samples were unreactive as per the EPA Reactivity Tests for sulfides and cyanides. The trace metal leachate levels were within the EPA Drinking Water Standard. Slag chemical analysis and other properties indicate that the material is not classified as a hazardous waste. Furthermore, the slag that is generated by the combustor falls under the Pennsylvania Coal Waste Product Recycling Act, and it can be recycled as an anti-skid material. As such it can be sold at prices in the $2 to $4/ton range to the PA Department of Transportation for road use. Detailed discussion of trace metal behavior in the combustor is given elsewhere[10].

## ECONOMICS OF RETROFIT OF COAL TECH'S COMBUSTOR TO INDUSTRIAL & UTILITY BOILERS.

The economics of utilizing the Coal Tech combustor have been analyzed for three cases. One is a new industrial scale power plant rated at 10 MWe output and designed as an independent power producer for power sales to a local utility. The other is a retrofit of an existing 250 MWe coal fired plant to meet current stack emission requirements. These two results were reported previously [7] using combustor performance data obtained prior to 1990. Based on the air cooled combustor performance prior to 1990, 75% NOx and 87% SO2 reductions were assumed in the analysis. The SO2 reduction was based on a two step process with combustor and boiler injection. An update of this information was reported recently [12] using the performance data as of the end of 1991. In that report[12], NOx reductions of 80% and SO2 reductions of 90%, with only combustor sorbent injection, were used in the analysis. However, even this data needs updating as very recent work indicates that SO2 reductions approaching 100% are achievable. The third application involves the integration of the air cooled combustor in high performance combined gas-steam turbine power cycles. The latter offer higher efficiencies and improved environmental performance when using the Coal Tech combustor. The concept will be briefly described. Results for this last case are not complete at this time.

(i). Economics of Retrofit of a 250 MWe Coal Fired Utility Power Plant.

The analysis [7] used the performance and cost data for the conversion cost of the 250 MWe coal plant specified in the DOE Clean Coal Solicitations[13]. The economic analysis estimated the cost of retrofitting this plant with 16 Coal Tech's combustors, each rated at a nominal 150 MMBtu/hr. 2.4% and 4.3% sulfur coals were assumed. The retrofit reduced the net power output of the plant from 250 MWe to 234.7 and 230.9 MWe for the 2.4%S and 4.3%S coals, and the heat rates from 9480 Btu/kW-hr to 10,098 and 10,264, respectively. The capital cost for the retrofit was about $54 million for both coals.. The unit O&M costs were 3.32 and 4.16 mills/kW-hr for the 2.4% and 4.3% coals, respectively. The capital cost of the retrofit are summarized in Table 1. It consists of the following sub-systems: Limestone storage, pulverization, and feed system; coal feed to the combustors; 16 combustors, including fans and ducting, and slag removal. Table 1 also shows the operation and maintenance costs as obtained with the cost estimating procedure in reference 13.

Since the purpose of the retrofit is to reduce SO2 and NOx emissions, the conversion cost analysis has been structured to allow a determination of the incremental cost of meeting these requirements. A 15 year equipment life was assumed because it was used in an EPA/EPRI[14] study to compare conventional wet stack scrubbing with limestone injection in a boiler, the so called LIMB process. The 15 year levelized annual operating costs were 8.29 mills/kW-hr and 9.07 mills/kW-hr for the 2.4%S and 4.3%S cases, respectively. These operating costs are about 20% less than the values quoted in the EPA/EPRI study[14] for 10 different LIMB cases. These costs are less than 1/2 of the equivalent wet flue gas scrubber costs.

The incremental capital costs were $230/kW, which is about 10% less than the FGD costs, and nearly double those for the LIMB costs as given in reference 14. However, the LIMB process does not remove sufficient SO2 to meet current air quality standards. The cost per ton of SO2 and NOx removed, levelized over 15 years was $225/ton for the 4.3%S and $343/ton for the 2.4%S coal. This compares with an average cost for five different LIMB sorbents of $752/ton for 3.36%S coal, and $924/ton for 1.92%S coal. In this case, only SO2 is removed[14]. The comparable FGD costs are $829/ton and $1359/ton for the high and low sulfur coals respectively. These costs will be further reduced as the more recent improvements in SO2 control are incorporated in the analysis.

(ii). Applications of Coal Tech's Combustor to a 10 MWe Industrial Power Plant

Using the data base generated in the 20 MMBtu/hr combustor project, a preliminary evaluation and design of an industrial boiler, utilizing a nominal 100 MMBtu/hr combustor, was performed. An output rating in the 7 to 10 MWe range was assumed. The estimated cost of the power plant was between $1400 and $1500/kW. With conventional private sector financing this plant is economical with coal fuels only in high power generation cost areas. However, with waste fuels, which qualify for lower interest rate financing, the plant yields very attractive economic returns for power sales, especially when combined with a steam host in a cogeneration mode.

(iii) Combined Gas Turbine/Steam Turbine Industrial Power Plant

Recently a study of the integration of the air cooled combustor in a combined gas-steam turbine power cycle was initiated. This configuration may yield more attractive economic returns than comparable natural gas fired, combined cycle, gas-steam turbine power plants. The study is in its early stages. The total power output is 20 MWe of combined steam-gas turbine power. Figure 5 shows a schematic arrangement of the power plant. The exhaust of a gas turbine, fired with natural gas, is used as combustion air for the coal fired, air cooled combustor. The latter is attached to a factory assembled industrial boiler, which produces steam in the 700-950 psi, 700-900F range for use in a condensing steam turbine. The gas turbine accounts for one-fourth to one-third of the total power output. Figure 5 shows a second boiler which is used as a heat recovery boiler in case the coal fired boiler is shutdown for maintenance. This configuration would be used in initial demonstration plants. In full commercial operation, the second boiler would also be coal fired with a second air cooled combustor, thereby improving the reliability of the entire system. Preliminary analysis of the cycle yielded an efficiency of about 34%, which is between 2 to 6% points higher than a simple steam cycle discussed in the previous sub-section..

## CONCLUSIONS

The three year effort (1987-1990) under the Clean Coal Round 1 Program was the first commercial scale demonstration of this air cooled, slagging coal combustor. The Clean Coal test effort provided an operational data base for the combustor. These data have been subsequently incorporated in an automatic computer controlled combustor operating system which has substantially improved its performance, its environmental control, and the durability of combustor materials.

$SO_2$ reductions with sorbent injection into the combustor is a complicated process that depends on the type of sorbent and on the combustor operating conditions Steadily improving results were obtained in Clean Coal tests and subsequent tests to the point where recently 90 to 95% $SO_2$ reductions were measured with calcium hydrate injection in the combustor. Further tests are planned whose objective is to achieve nearly 100% reduction.

With fuel rich combustion in the combustor, two-thirds reduction of NOx was measured to less than 200 ppm upstream of the particle scrubber. An additional reduction to 140 ppm was obtained as a result of action by the wet particulate scrubber.

All the slag removed from the combustor has produced trace metal leachates well within the EPA Drinking Water Standard when subjected to the EP TOX leach test.

Slag/sorbent retention in the combustor and exit nozzle is a function of many operating variables, some of which conflicts with requirements for efficient combustion and stack NOx and $SO_2$ control. Under the fuel rich conditions needed for control of these gas emissions, slag retention averaged 72%, with considerable scatter due to the wide range of operating conditions. Of the carryover ash, somewhat over one-half deposited on the floor of the boiler. Deposits on the boiler tubes were dry and easily removable..

Stack particle emissions requirements for the test site were met with the venturi particulate scrubber. A test under typical coal fired operating conditions yielded an emission level of 0.22 lb/MMBtu, which was well within local air quality requirements.

Up to 99% combustion efficiencies were measured at the stack with stoichiometric ratios (SR) in the range of 0.65 to 1.1 in the combustor and with final combustion in the boiler. Combustor turndown of 3 to 1 was achieved in a range of 8 MMBtu/hr to 20 MMBtu/hr.

The 15 year levelized cost of retrofitting a 250 MW power plants with this technology is $343/ton of $SO_2$ and NOx, with 2.4% sulfur coal. For 4.3% sulfur coal, the cost is $225/ton. The capital cost is $229/kW.

The combustor is being evaluated for application to a combined gas-steam turbine power plant, where its use appears to offer significant performance and cost advantages.

Finally, the combustor data is now sufficient to design commercial units up to 100 MMBtu/hr.

# THE HEALY CLEAN COAL PROJECT

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## ABSTRACT

The Healy Clean Coal Project involves the permitting, design, construction, operation, and testing of a new 50 MWe nominal pulverized coal-fired power plant. The plant features the innovative integration of TRW's slagging combustion system with Joy's advanced flue gas desulfurization system. The integration of these technologies is expected to cost effectively result in low emissions of $NO_x$ and $SO_x$. This paper presents a description of the technologies and the status of the project.

## INTRODUCTION

The Healy Clean Coal Project (HCCP) is jointly funded by the Alaska Industrial Development and Export Authority (AIDEA) and the U.S. Department of Energy (DOE). The HCCP was selected by DOE in Round III of its Clean Coal Technology Program. AIDEA has assembled a team comprised of TRW, Inc. (TRW), Joy Technologies, Inc. (Joy) together with its European associate Niro Atomizer (Niro), Golden Valley Electric Association, Inc. (GVEA), Usibelli Coal Mine, Inc. (UCM), and Stone & Webster Engineering Corporation (SWEC) to design, build, operate, and test the plant through a one year demonstration phase.

The primary objective of the HCCP cost-shared project is to demonstrate a new power plant design which features innovative integration of an advanced combustor and heat recovery system coupled with both high and low temperature emission control processes. The parties anticipate that, if the demonstration project is successful, the technology could become commercialized during the 1990's and will be capable of (1) achieving significant reductions in the emissions of sulfur dioxide ($SO_2$) and the oxides of nitrogen ($NO_x$) from existing facilities to minimize environmental impacts such as transboundary and interstate pollution and/or (2) providing for future energy needs in an environmentally acceptable manner.

AIDEA is a state agency whose goal is to assist in the development of Alaskan industry and exports. Traditionally, AIDEA has participated in small projects where private investors have needed assistance. The HCCP satisfies AIDEA's objectives of development of Alaskan industries through demonstration of both economical and environmentally acceptable combustion of low-grade Alaskan coals. However, HCCP places unique pressures on AIDEA. The project is a major investment for AIDEA. The cash flow from the HCCP is important to other AIDEA investments. AIDEA has no experience in the management, operation, and maintenance of power plants and traditional performance guarantees were not obtainable. Thus, the HCCP financial and technical performance is extremely important to AIDEA.

These conditions have required AIDEA to adopt several project strategies. These are:

- Financial "not to exceed" caps on contracts to limit risk and rigid cost containment controls and management approaches to anticipate and mitigate cost overruns.
- Fund pilot and demonstration tests to assure technical performance.
- Rely on the experienced staff of GVEA and their Unit No. 1 operations team to operate the plant under a cost sharing operation and maintenance (O&M) agreement, where both parties share the gains or losses relative to O&M costs.
- Fully staff the demonstration period to not only assure the demonstration objectives but to also train operators, improve performance, and upgrade the HCCP if necessary.

The demonstration project is proposed to be built adjacent to GVEA's existing Healy Unit No. 1 pulverized coal power plant. The site is located near Healy, Alaska (Figure 1). Alaskan bituminous and subituminous coals will be tested. GVEA will operate, maintain, and purchase power from the new power plant facility.

Coal from the adjacent UCM mine will be crushed, pulverized, and burned at the proposed facility to generate high-pressure steam that will be used by the steam turbine-generator to produce electricity. Emissions of $SO_2$ and $NO_x$ from the plant will be controlled using TRW's combustion systems with limestone injection, in conjunction with a boiler supplied by Foster Wheeler. Further $SO_2$ and particulate removal will be accomplished using Joy's Activated Recycle Spray Dryer Absorber (SDA) System.

The total project activities include permitting, design, procurement, fabrication, construction, start-up, testing, and reporting of results. The AIDEA/DOE Cooperative Agreement is in place for a total of $215,000,000. Construction of the demonstration facility is expected to start in the spring of 1993 and continue for 2.5 years. Following completion of the

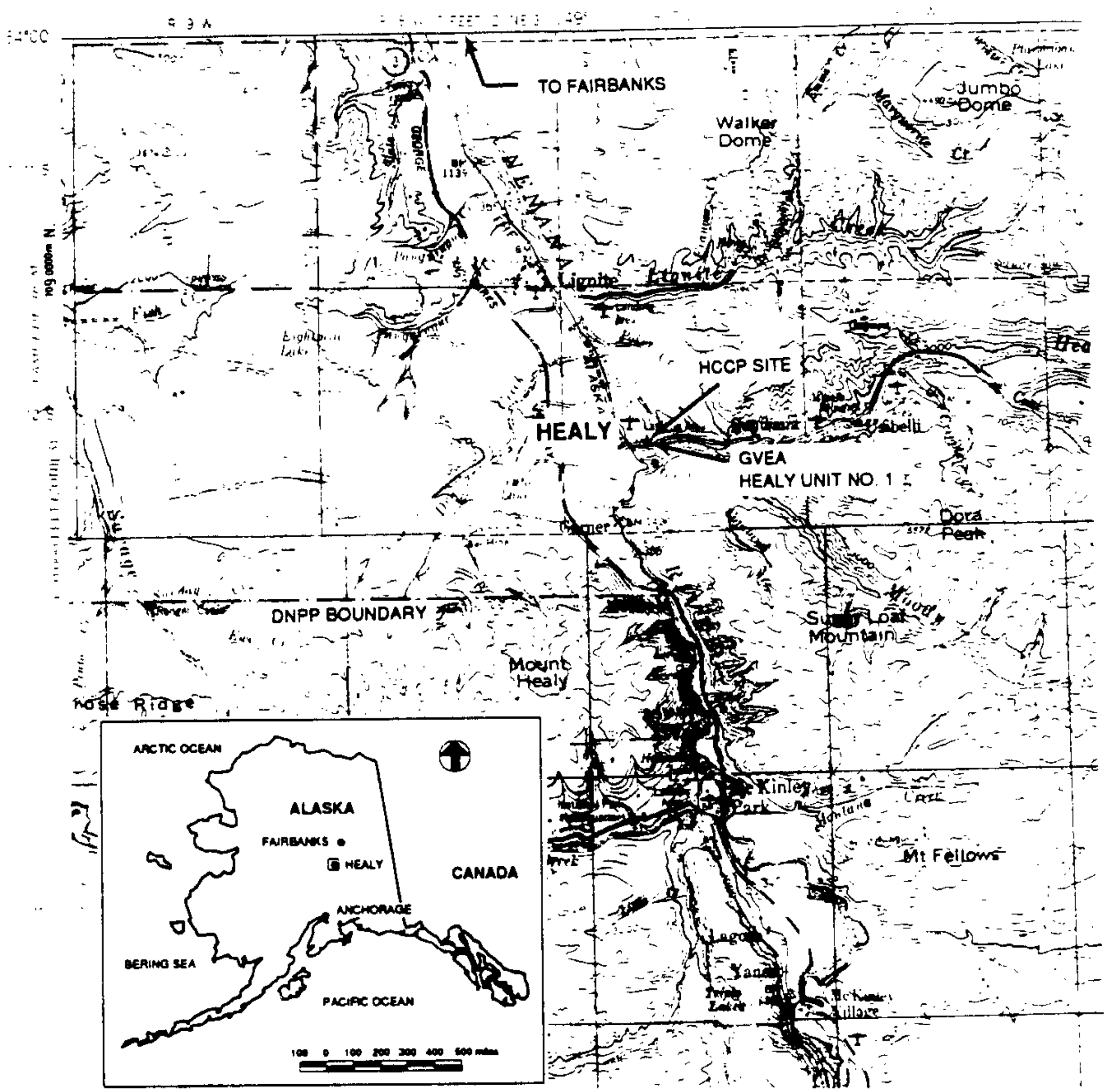


**Figure 1: Site Location**

demonstration test program, the plant is expected to continue to operate and be maintained as a commercial utility electric generation station.

The proposed HCCP is to be a nominal 50 MWe facility consisting of two pulverized coal-fired combustion systems, a boiler, a spray dryer absorber with activation and recycle equipment, a fabric filter, a turbine-generator, coal and limestone pulverizing and handling equipment, and associated auxiliary equipment (Figures 2 and 3).

The specific objectives of the HCCP demonstration are to:

- Demonstrate the use of Alaskan, low-sulfur bituminous and subituminous coals of medium to high ash and moisture content.
- Demonstrate the feasibility of large utility boiler repowering capability of the TRW Combustion System.
- Demonstrate large utility boiler retrofit capability of the TRW Combustion System on pulverized coal and cyclone furnace design boilers with improved performance, and lower $NO_x$, $SO_2$, and particulate emissions.
- Demonstrate the enhanced capability of the TRW Combustion System for simultaneous $NO_x$ and $SO_2$ removal when combined with advanced back-end $SO_2$ absorption techniques and furnace air staging.
- Determine the cost effectiveness of the technology especially in terms of reduced operating costs due to the system's capability to burn low grade/waste coals.
- Demonstrate the low operating costs for Joy's Activated Recycle Spray Dryer Absorber System utilizing limestone as a reagent.

The air pollution control system that will be demonstrated by the project (Figure 4) incorporates the following major components:

- TRW Combustion System
- Foster Wheeler Furnace
- Joy SDA, Baghouse, and Sorbent Activation Systems

Figure 2: Artist Rendering

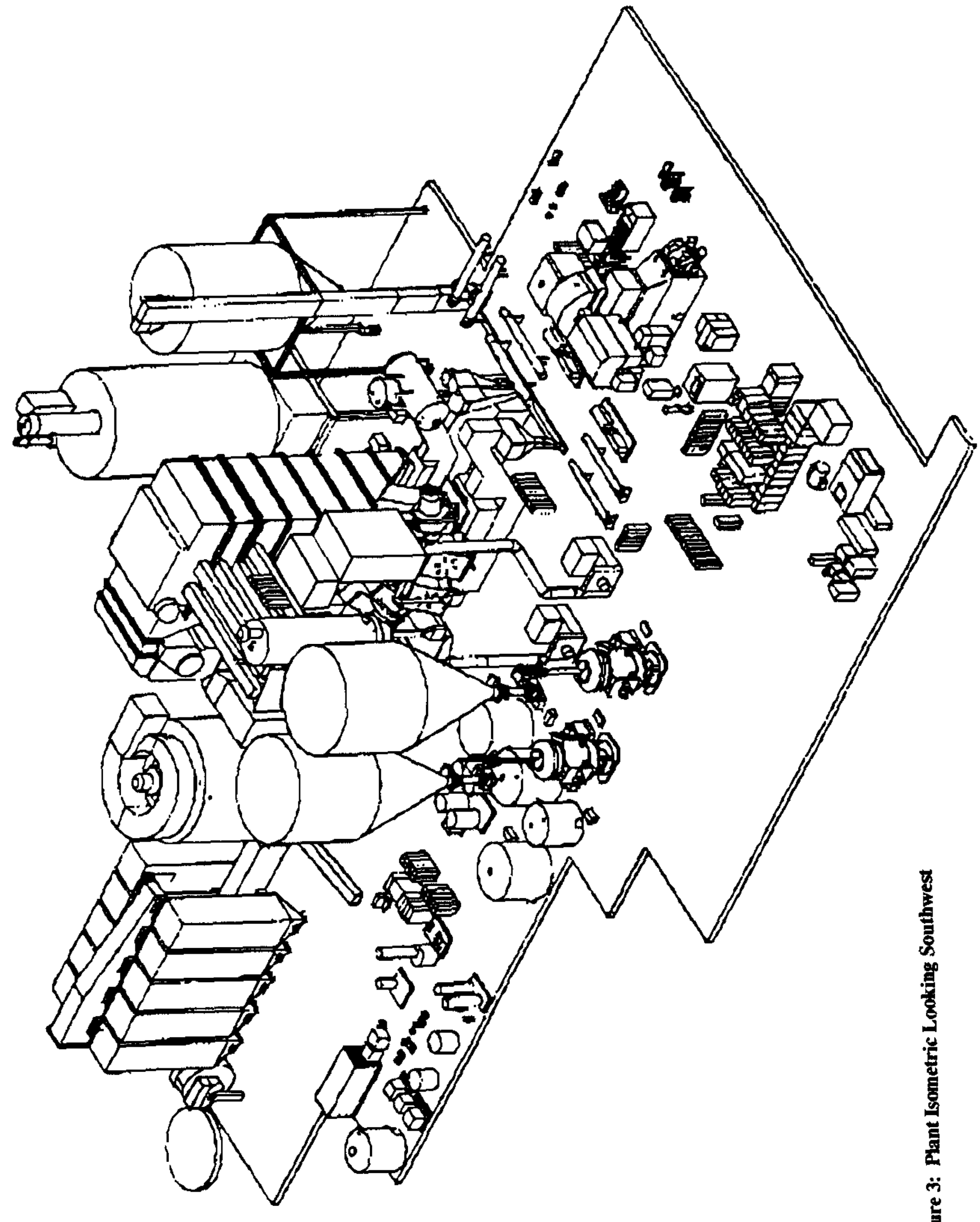

Figure 3: Plant Isometric Looking Southwest

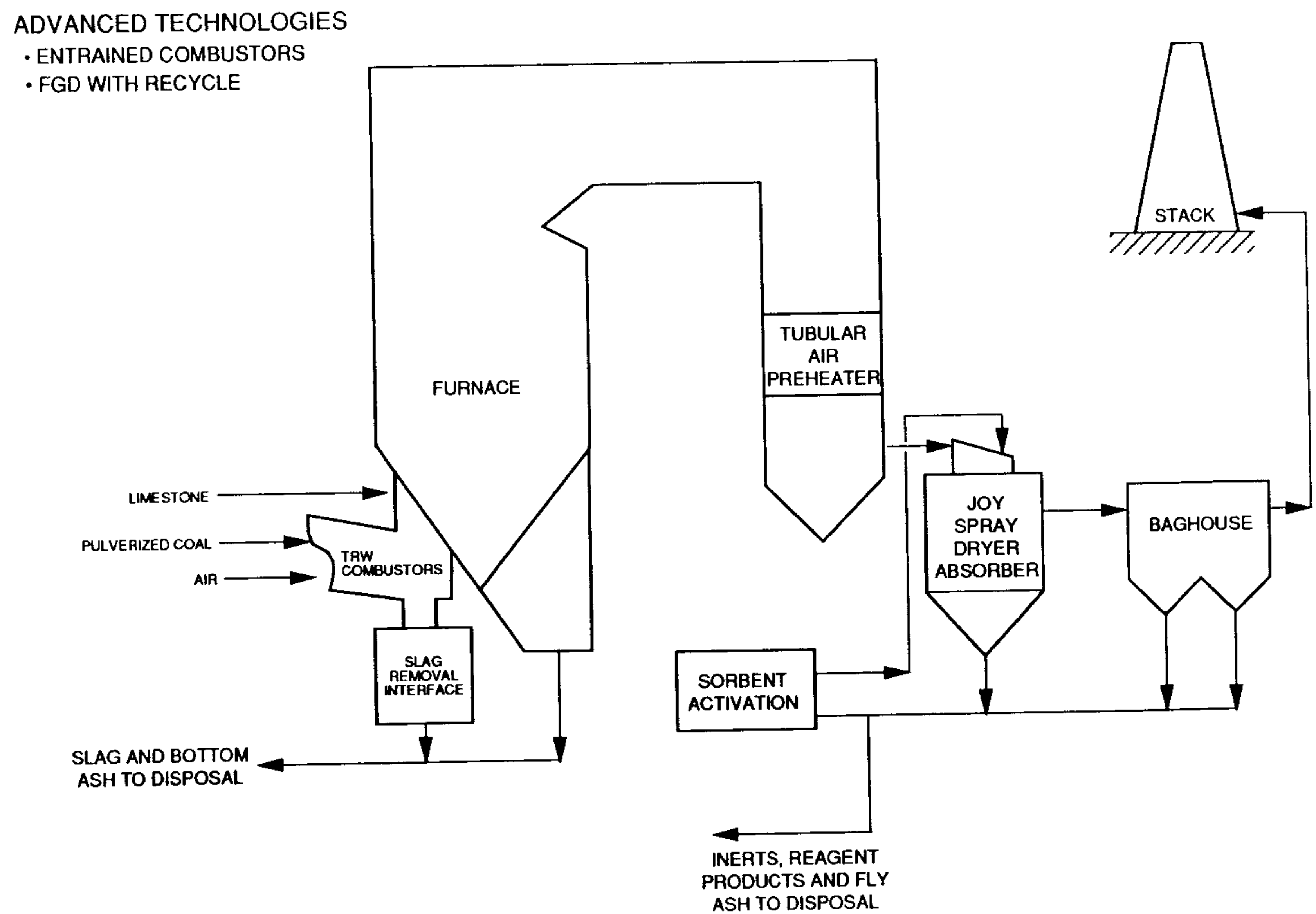


Figure 4: Process Flow Diagram

The integrated air pollution control process that results from the HCCP configuration of these components has been designed to minimize emissions of $SO_2$, $NO_x$, and particulates from the facility while firing a broad range of coals.

$NO_x$ emissions are reduced in the coal combustion process by use of the fuel and air-staged combustor system and a boiler that controls fuel and thermal-related conditions which inhibit $NO_x$ formation. The slagging combustor/boiler system also functions as a limestone calciner and first stage $SO_2$ removal device in addition to its heat recovery function. Secondary and tertiary $SO_2$ capture are accomplished by a single SDA vessel and a fabric filter respectively. Ash collection in the process is first achieved by the removal of molten slag in the coal combustors followed by fly ash particulate removal in the fabric filter system downstream of the spray dry absorber vessel.

## TECHNOLOGY DESCRIPTION

### TRW Combustion System

The TRW Combustion System will be designed to be installed on the boiler furnace to provide efficient combustion, maintain effective limestone calcination, and minimize the formation of $NO_X$ emissions. As shown in Figure 5, the main system components include a precombustor, main combustor, slag recovery section, tertiary air windbox, pulverized coal and limestone feed system, and combustion air system. Figure 6 shows a schematic of the general boiler arrangement and the combustion system installation for the HCCP. In this unique arrangement, the slagging combustors are bottom mounted on the boiler hopper to yield optimum operation and cost benefits. Bottom mounted combustors offer the following advantages over a "wall" mounted configuration:

- This arrangement is particularly suited to retrofit applications with space constraints typical in existing plants and provides the easiest access to the furnace.

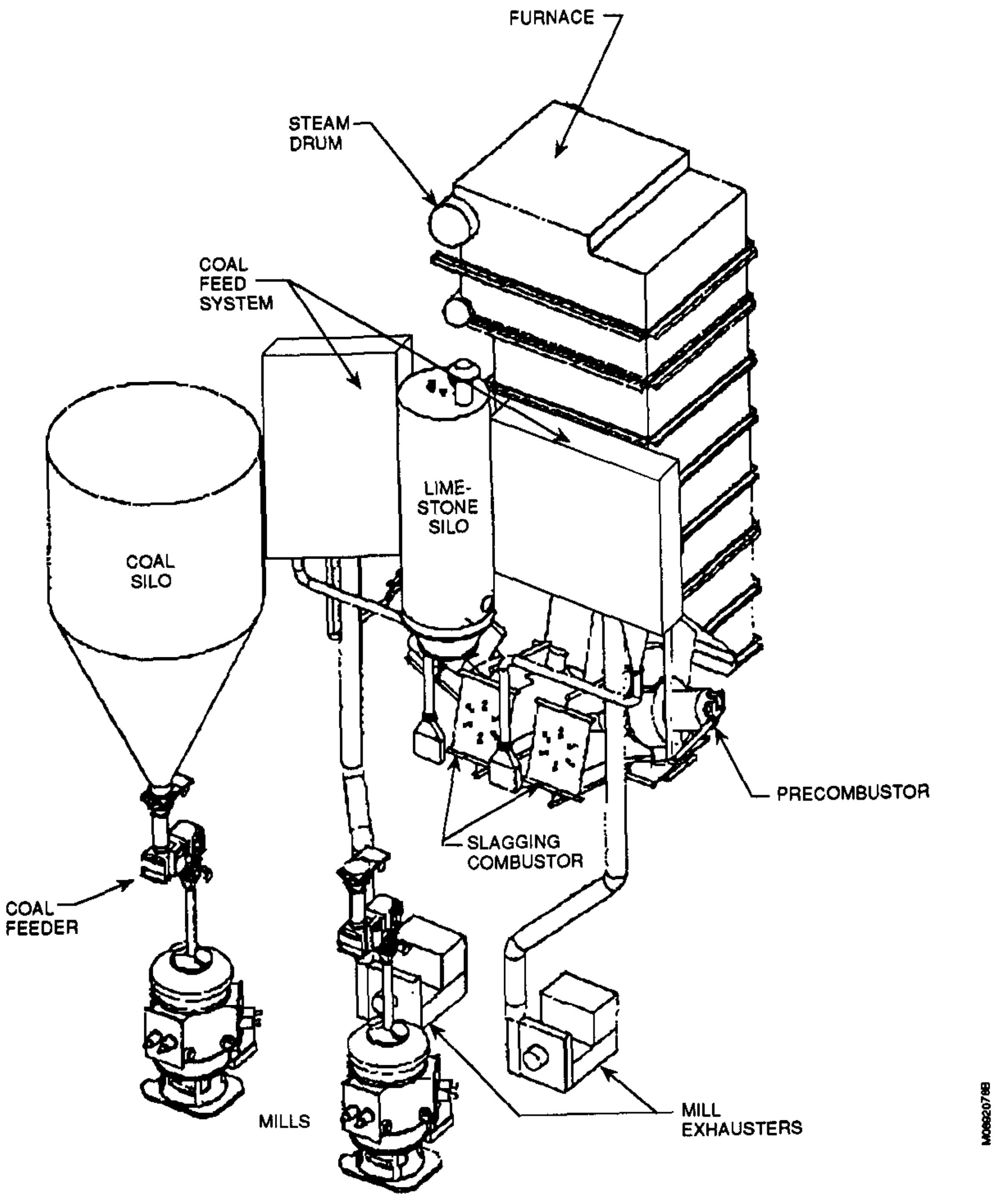


Figure 5: TRW Entrained Coal Combustion System

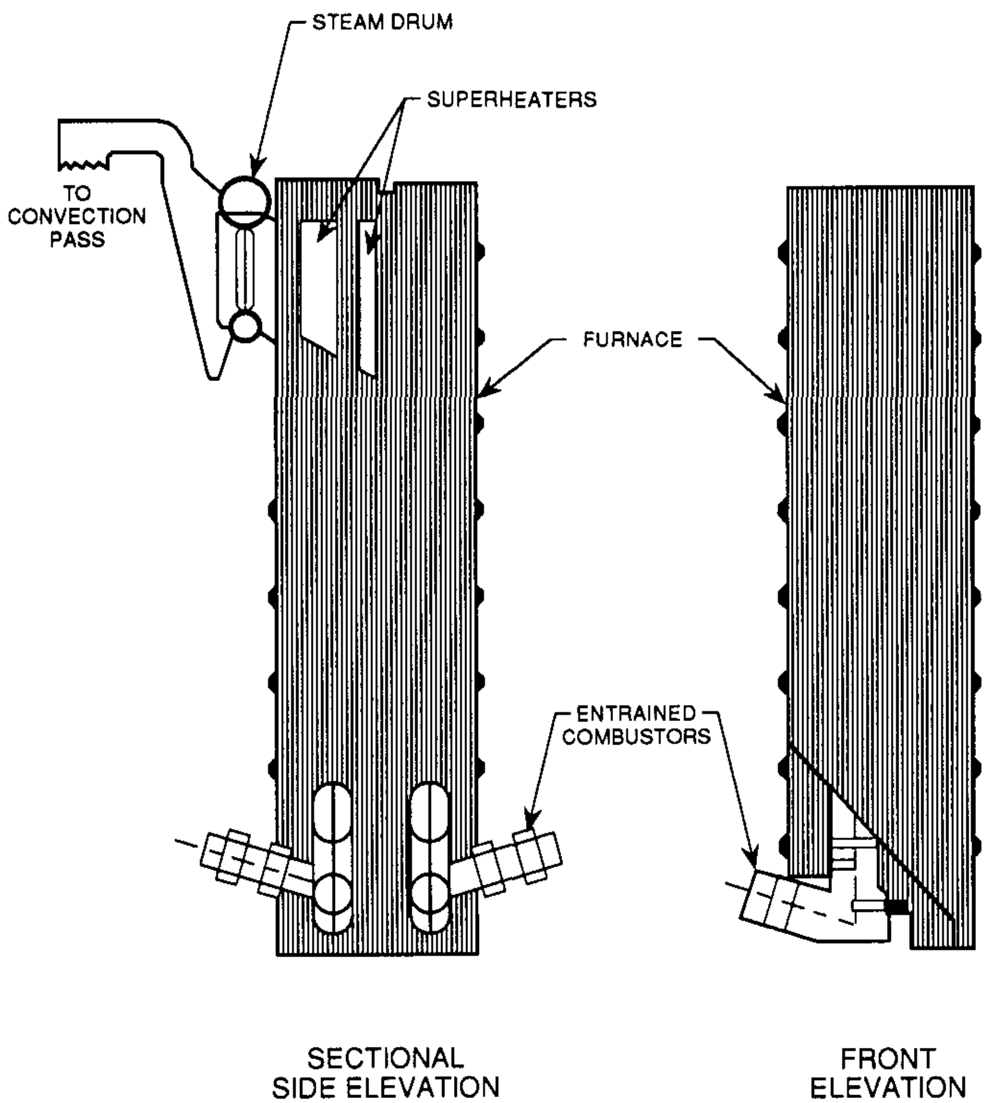


**Figure 6: HCCP General Boiler Arrangement and Entrained Combustors Installation**

- Support design is less complex when hanging from beneath the furnace.
- Upfiring into the large furnace cavity prevents flame impingement on the furnace walls.
- The slag removal system can be located at ground level.

The coal-fired precombustor is used to increase the air inlet temperature to the main combustor for optimum slagging performance. It burns approximately 25-40 percent of the total coal input to the combustor. A Foster Wheeler low $NO_x$ burner was selected for the precombustor coal/air injection. Combustion is staged to minimize $NO_x$ formation.

The main slagging combustor consists of a water-cooled cylinder which is sloped toward a slag opening. The remaining coal is injected axially into the combustor, rapidly entrained by the swirling precombustor gases and additional air flow, and burned under substoichiometric (fuel-rich) conditions for $NO_x$ control. The ash contained in the burning coal forms drops of molten slag and accumulates on the water-cooled walls as a result of the centrifugal force resulting from the swirling gas flow. The molten slag is driven by aerodynamic and gravity forces through a slot into the bottom of the slag recovery section where it falls into a water-filled tank and is removed by the slag removal system. Approximately 70 to 80 percent of the ash in the coal is removed as molten slag.

The hot gas, containing carbon monoxide and hydrogen, is then ducted to the furnace from the slag recovery section through the hot gas exhaust duct. To ensure complete combustion in the furnace, additional air is supplied from the tertiary air windbox to $NO_x$ ports and to final overfire air ports located in the furnace.

Pulverized limestone ($CaCO_3$), for $SO_2$ control, is fed into the combustor. While passing into the boiler most of the limestone is decomposed to flash calcined lime by the following reaction:

$$CaCO_3 + \text{heat} \rightarrow CaO + CO_2\uparrow \quad (1)$$

The mixture of this lime (CaO) and the ash not removed by the combustors is called Flash Calcined Material (FCM). Some sulfur capture by the entrained CaO also occurs at this time, but the primary $SO_2$ removal mechanism is through a multiple step process of spray drying the slurried and activated FCM solids.

The first part of the coal feed system consists of conventional, pulverized coal equipment including steel coal silos, gravimetric feeders, mills, and mill exhauster fans (Figure 5). However, a unique flow splitter and cyclone system is designed which will decouple the coal from the mill air as well as divide the coal flow in the proper proportion to the precombustors and main combustors.

The limestone feed system also consists of conventional equipment including the silo, feeder, blowers, and injection nozzles. The injection nozzles are placed at the combustor to furnace interface to ensure good mixing with the exhaust gases.

Joy System

Once FCM is produced in the furnace via equation (1), it is removed in the fabric filter system as depicted in the flow schematic shown in Figure 7. A portion of the material is transported to disposal. Most of the material however is conveyed to a mixing tank, where it is mixed with water to form a 45 percent FCM solids slurry. The lime rich FCM material is slaked by agitation of the suspension. A portion of the slurry from the mixing tank passes directly through a screen to the feed tank, where the slurry is continuously agitated. The remainder of the slurry leaving the mixing tank is pumped to a grinding mill, where the suspension is further mechanically activated by abrasive grinding.

By grinding the slurry in a mill, the FCM is activated by a mechanical process whereby the overall surface area of available lime is increased, and coarse lime particle formation is avoided. Thus, the mill enhances the slaking conditions of the FCM and increases the surface area for optimal $SO_2$ absorption. FCM slurry leaving the tower mill is transported

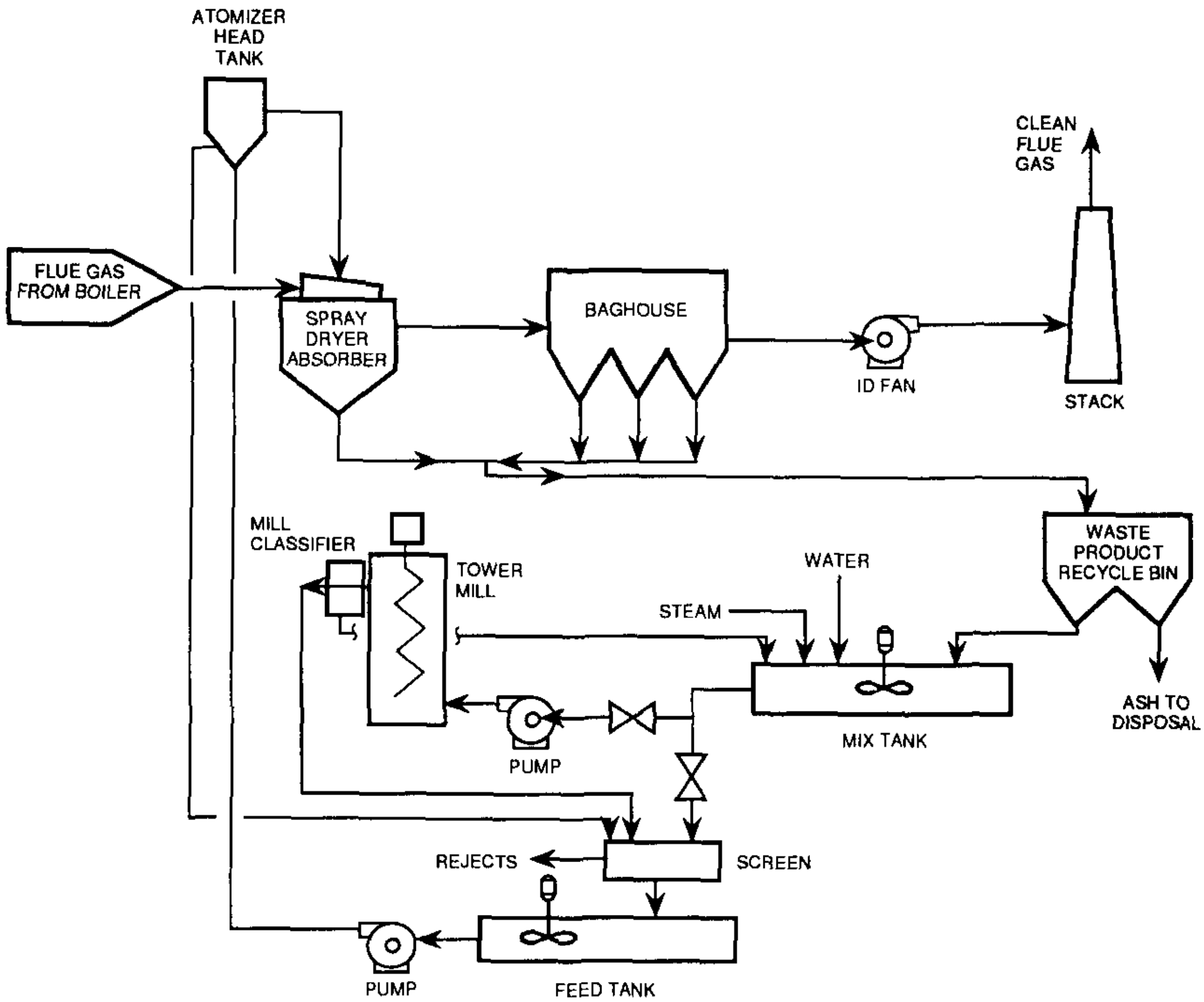


**Figure 7: Joy Recycle/Reactivation SDA System**

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through the screen to the feed tank.

Feed slurry is pumped from the feed tank to the SDA, where it is atomized via rotary atomization using Joy dry scrubbing technology. Sulfur dioxide in the flue gas reacts with the FCM slurry as water is simultaneously evaporated. The dry reaction product is removed via the SDA hopper or baghouse catch. Sulfur dioxide is further removed from the flue gas by reacting with the dry FCM on the baghouse filter bags.

The HCCP is an integrated system for the combustion of coal and control of all emissions. The slagging combustor, furnace, and enhanced recycle SDA system all play a part in reducing emissions from the plant. The slagging combustor inhibits $NO_x$ production, generates the FCM for capture of $SO_2$, and reduces the potential amount of fly ash by up to 80 percent. The furnace further contributes to the $NO_x$ reduction process and begins the $SO_2$ removal process. The recycle/reactivation SDA system, which includes the pulse-jet baghouse, completes the collection of particulate and $SO_2$.

Removal of any single component in the integrated system results in ramifications on other components. For example, removal of the slagging combustor and replacement with low $NO_x$ burners increases the ash loading out of the furnace by nearly 400 percent, eliminates the production of FCM which requires the conversion of the recycle/reactivation SDA system to a conventional lime spray dryer system, and possibly increases $NO_x$ emissions. Replacement of the spray dryer with a wet scrubber eliminates the need to generate FCM since all of the particulate would be collected upstream of the wet scrubber in a fabric filter or electrostatic precipitator where there is no way of separating fly ash from FCM.

## $NO_x$ Control

Emissions of $NO_x$ are expected to be demonstrated to levels significantly below EPA New Source Performance Standards (NSPS) in the boiler by using slagging combustor technology and known combustion techniques.

The HCCP combustors achieve $NO_x$ control as a combination of the following factors:

- The combustor functions as a well-stirred reactor under substoichiometric conditions for solid fuel combustion, converting the solid fuel components to a hot, partially oxidized fuel gas in an environment conducive to destroying the complex organic fuel bound nitrogen compounds which could easily be oxidized to $NO_x$ in the presence of excess oxygen.

- The combustor water cooled enclosure additionally absorbs approximately 10 to 25 percent of the total available heat input to the combustor.

These two conditions together reduce the potential for encountering combustion temperatures in the furnace sufficient for decomposition of molecular nitrogen compounds in the combustion air into forms which can produce thermal $NO_x$ emissions as excess oxygen is made available.

When the exhaust gases leave the combustor, the coal has already been mixed with approximately 80 to 90 percent of the air theoretically necessary to complete combustion. A portion of the remaining 10 to 20 percent is then allowed to mix slowly with the hot fuel gases exiting the combustor and entering the furnace. The hot gases radiate their heat to the furnace walls at rates faster than combustion is allowed to occur so that gas temperatures slowly decay from those at the furnace entrance. After the furnace gases have cooled sufficiently, a second and possibly third stage of furnace combustion air injection is performed as necessary to complete the coal combustion process in an oxidizing, controlled manner so that combustion gas temperatures are maintained below the thermal $NO_x$ floor where significant $NO_x$ formation begins. This is in contrast with a traditional coal-fired furnace where the pulverized coal is burned in suspension at high excess air rates. Resulting gas temperatures from PC furnaces typically rise significantly above the 2800°F temperature maintained in the slagging combustor and downstream furnace. In the traditional furnace, the pulverized coal is relatively poorly mixed with conventional low $NO_x$ wall burner/suspension firing techniques, and local areas of combustion in the presence of stoichiometric oxygen create hot zones within the flame. These hot, turbulent stoichiometric zones can produce significant $NO_x$ levels in the area of burner throats. This tendency for high, localized $NO_x$ formation is minimized with the slagging combustor through slow, controlled mixing of furnace combustion air with the partially cooled, well-mixed fuel gases discharging from the combustor into the lower furnace $NO_x$ control zone.

The general relationship between low $NO_x$ emissions and combustor stoichiometry resulting from tests at TRW's 50 MMBtu/hr Cleveland demonstration facility and their Fossil Energy Test Site (FETS) are shown in Figures 9 and 10. The Cleveland facility operates with low excess air and no overfire air or $NO_x$ ports in the furnace.

The curve in Figure 8 shows that $NO_x$ emissions (while firing bituminous coal) are minimized for the Cleveland combustion process at approximately 30 percent of the current NSPS when the slagging combustor system is operated at a stoichiometry of 0.70 and when all of the final combustion air is added at the combustor exit nozzle at the entrance to the boiler furnace. The HCCP will demonstrate additional $NO_x$ reduction techniques including furnace $NO_x$ ports and furnace over-fire air injection (Table 1).

| POLLUTANT | DEMONSTRATION OBJECTIVES | PROPOSED PSD PERMIT LIMITS (ANNUAL) | NEW SOURCE STANDARDS REQUIREMENTS |
|---|---|---|---|
| $NO_x$ | <0.2lb/MMBtu | 0.35 LB/MMBtu (988 tpy) | 0.50 lb/MMBtu |
| $SO_x$ | >90% Removal | 0.09 lb/MMBtu [a] (243 tpy) | 70% Removal |
| Particulates | <0.015lb/MMBtu | 0.02 lb/MMBtu (56 tpy) | 0.03 lb/MMBtu |

a Represents 80 percent removal at steam generator maximum continuous rating.

**Table 1. Summary of HCCP Emissions**

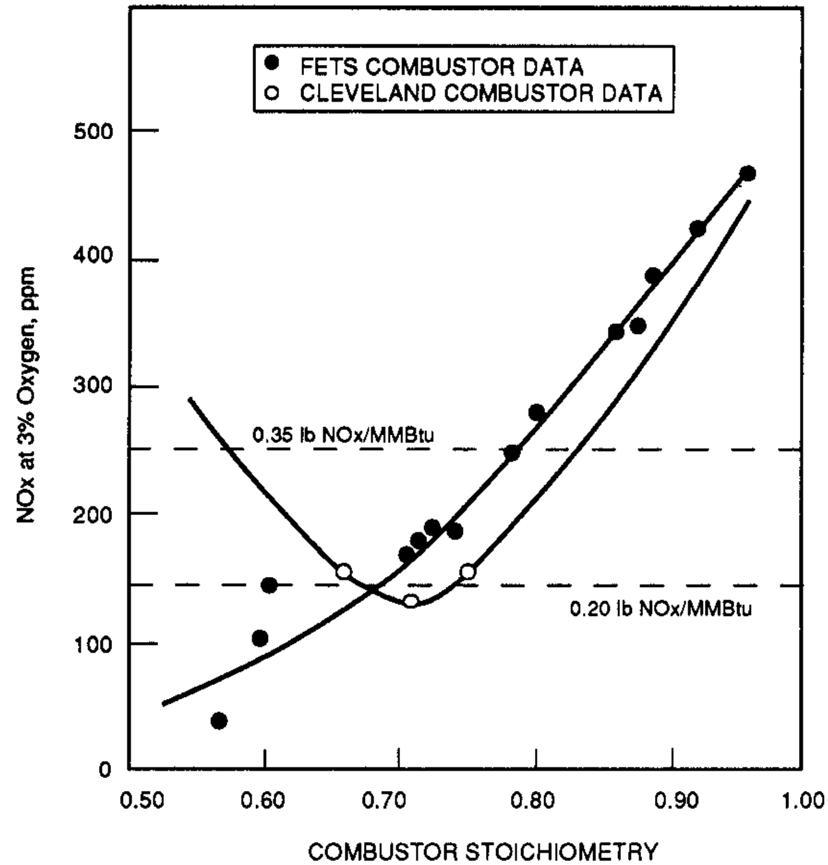


**Figure 8: NOx Emissions as a Function of Combustor Stoichiometry for Bituminous Coal Burned in the FETS Laboratory Combustor and the Cleveland Combustor.**

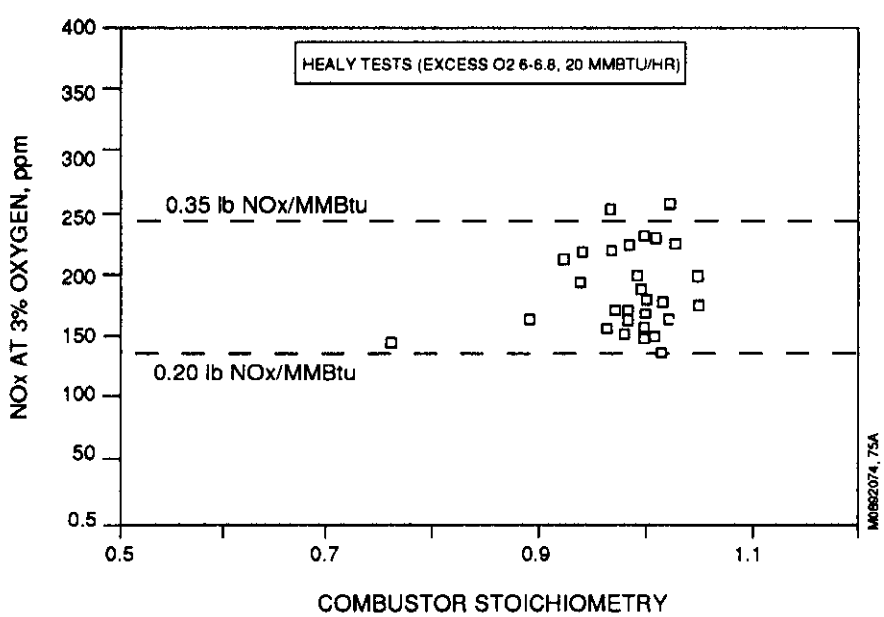


**Figure 9: NOx Emissions as a Function of Combustor Stoichiometry for HCCP Coal Burned in the Cleveland Combustor.**

Figure 9 presents $NO_x$ emissions from the Cleveland facility as a function of main combustor stoichiometry while firing UCM coal. As can be observed from the figure, very low $NO_x$ emissions are achievable by operating the combustor near or slightly below stoichiometry while firing the HCCP coal. These results indicate that $NO_x$ emissions are only mildly dependent on combustor stoichiometry thus providing operating flexibility.

$SO_2$ Control

Emission levels of $SO_2$ are controlled to and below NSPS levels using the Joy recycle/reactivation SDA system.

The coals to be fired in the HCCP combustion system (shown in Table 2), are low sulfur, high moisture, low heating value fuels from the UCM mine. While the project will demonstrate higher $SO_2$ removal efficiencies, the sulfur content is so low that only a 70 percent $SO_2$ removal efficiency is required to satisfy NSPS requirements. Coal 1 is a run-of-mine coal, where care was taken in the mining operation to minimize the amount of overburden and lenses included with the coal. Coal 2 is the performance coal and consists of 50 percent run-of-mine and 50 percent waste coal with the waste coal being a lower heating value fuel with significantly more ash. An advantage of the slagging combustor is that it can burn low quality coals and still meet emissions and performance requirements.

Tests were performed at the TRW facility in Cleveland and Niro's facilities in Copenhagen to confirm design conditions for the HCCP. In addition to confirming combustor capability when firing UCM coal, another purpose of the tests in Cleveland was to generate FCM that could be used in the Niro test facility. Coal and limestone that are to be used by the HCCP were used for the tests.

| | Coal 1 Run-of-Mine | Coal 2 Performance Blend |
|---|---|---|
| Proximate Analysis | | |
| Moisture, % | 26.35 | 25.11 |
| Ash, % | 8.20 | 16.60 |
| Volatile, % | 34.56 | 30.78 |
| Fixed Carbon, % | 30.89 | 27.51 |
| Total, % | 100.00 | 100.00 |
| HHV, Btu/lb | 7,815 | 6,960 |
| Ultimate Analysis | | |
| Moisture, % | 26.35 | 25.11 |
| Ash, % | 8.20 | 16.60 |
| Carbon, % | 45.55 | 40.57 |
| Hydrogen, % | 3.45 | 3.07 |
| Nitrogen, % | 0.59 | 0.53 |
| Sulfur, % | 0.17 | 0.15 |
| Oxygen, % | 15.66 | 13.94 |
| Chlorine, % | 0.03 | 0.03 |
| Total | 100.00 | 100.00 |
| Elemental Ash Analysis | | |
| Silicon Dioxide, % | 38.61 | 65.69 |
| Aluminum Oxide, % | 16.97 | 11.09 |
| Titanium Dioxide, % | 0.81 | 0.52 |
| Ferric Oxide, % | 7.12 | 4.90 |
| Calcium Oxide, % | 23.75 | 10.62 |
| Magnesium Oxide, % | 3.54 | 1.87 |
| Potassium Oxide, % | 1.02 | 1.16 |
| Sodium Oxide, % | 0.66 | 0.65 |
| Sulfur Trioxide, % | 5.07 | 2.28 |
| Phosphorus Pentoxide, % | 0.48 | 0.30 |
| Strontium Oxide, % | 0.23 | 0.11 |
| Barium Oxide, % | 0.44 | 0.22 |
| Manganese Oxide, % | 0.06 | 0.04 |
| Undetermined, % | 1.24 | 0.55 |
| Total, % | 100.00 | 100.00 |

**Table 2. Coal and Ash Analysis**

Results from the Niro tests show that:

- $SO_2$ removal efficiencies of greater than 90% can be expected under certain operating conditions.
- $SO_2$ absorption is increased by FCM activation through heating or grinding.
- The utilization of the FCM depends on the SDA outlet temperature. The lower the outlet temperature, the better the utilization.
- Utilization of the FCM has been found to be better with activation than expected with lime at the same conditions.

Particulate Control

Particulate emissions control on the HCCP is obtained via the slagging combustors and by a pulse-jet baghouse. Each of ten fabric filter compartments will contain 225 six-inch diameter fiberglass bags. The effective length of each bag is 20'-0"and the gross air-to-cloth ratio is 2.8:1. The HCCP will demonstrate the effectiveness of a pulse-jet baghouse in removing the FCM particulate emissions.

It should be noted that a significant portion of the coal ash never leaves the furnace with the flue gases, since it is estimated that approximately 70 to 80 percent of the ash in the coal will leave the slagging combustors as slag.

Testing to Date

The linchpin of the HCCP has and continues to be a staged program of physical testing to understand, prove, and enhance the slagging combustor technology. This program has included:

- Pilot testing the combustor with UCM coals at the TRW test facility in Cleveland, Ohio in April 1991.
- Pilot testing of the Joy SDA process in Copenhagen in August 1991.
- FWEC boiler cold flow model testing of the furnace in St. Catherine's, Ontario in April to June 1992.

- Numerous Healy site tests including the emission testing of the GVEA Unit No. 1, coal unloading and conveying tests to establish capacities of existing equipment, coal flowability tests to determine hopper and silo configuration, and wastewater characterization and capacity.

- TRW cold flow model testing of the direct coal feed system and combustor components at TRW facilities at Space Park, California in June 1992.

- Full size precombustor and direct coal feed system tests at TRW's San Juan Capistrano, California site started in September 1992.

All testing is complete with the exception of the precombustor tests at San Juan Capistrano which are currently ongoing. The results of these tests have been used by SWEC to finalize design interfaces and by AIDEA to verify cost and performance assumptions made in the financial proformas. These tests have proven to be a vital part of proving technology and assuring the financial viability of the project.

## TECHNOLOGY DEVELOPMENT

The TRW combustion system is a significant advancement to cyclone combustion technology. There are over 1,000 cyclone furnace units in the U.S. electric utility industry. Many cyclone furnace units are also in operation in the United Kingdom, Germany, and the former USSR. Cyclone furnaces have generally been eclipsed by pulverized coal-fired furnaces due to the following:

- Cyclone furnaces have a two-stage slag tapping requirement of the unique wet bottom furnace design which limits its turndown capabilities with medium and high ash fusion temperature coals.

- Cyclone furnaces create a reducing coal combustion environment that occurs at the pressure parts of the cyclone furnace due to its "wall burning" design characteristics when fired with crushed coal.

- Cyclone furnaces have inherently high $NO_x$ emissions when operated at high enough excess air levels to prevent problems with corrosion due to reducing environments in the cyclones.

TRW developed a slagging combustor which resembles a cyclone furnace in that it employs a centrifugal motion for burning coal and forms a molten slag which is removed. However, the TRW slagging combustor has potentially resolved the problems associated with cyclone furnaces due to the following:

- Approximately 70% of the ash is reliably removed as a liquid slag from the combustor with a reasonable turndown on a wide range of coals. This improved turndown capability for the TRW slagging combustor over the cyclone furnace is due to the single stage tapping capability inherent in the TRW design.

- Pulverized coal is "entrained" and burned in flight within the combustor cavity as opposed to "wall burning" with crushed coal.

- The TRW slagging combustor is operated substoichiometrically resulting in low $NO_x$ formation.

- The temperature of the slagging combustor exhaust gases result in "flash calcination" of limestone. Significant sulfur capture is possible in the furnace. In addition, the flash calcined limestone will be used as the reagent in the Joy flue gas desulfurization system.

The HCCP represents significant advancement in the state of the art for slagging combustors over any previously planned demonstrations for the following reasons:

- A major boiler manufacturer, Foster Wheeler, has taken an active interest in the technology.

- The TRW slagging combustor will be fully integrated into the power plant design for the first time with a conventional steam cycle and coal preparation system.

- A large, water cooled, vertical shaft furnace will be available to determine the slagging combustor's substoichiometric, premixed combustion concept to be tested for in-furnace simultaneous $NO_x$ and $SO_2$ removal capabilities. It will be possible to compare test program results against the best that low $NO_x$ burners could do in the same furnace.

The HCCP is an important step in demonstrating the capabilities of the slagging combustion technology.

## PROJECT SCHEDULE

The HCCP project schedule was initiated in April, 1991 with the execution of the Cooperative Agreement. Environmental data collection had been started prior to execution of the Cooperative Agreement. The initial operation of the unit and start of demonstration testing is scheduled for January, 1996. The demonstration testing will be conducted for 1 year with commercial operation scheduled for January, 1997 (Table 3).

| | |
|---|---|
| State grant ($25,000,000) | 5/89 |
| Proposal submitted | 8/89 |
| DOE selection | 12/89 |
| AIDEA/DOE Cooperative Agreement | 4/91 |
| Alaska Public Utility Commission approval | 9/92 |
| Receive permits/environmental impact statement | 3/93 |
| Start construction | 3/93 |
| Commence demonstration tests | 1/96 |
| Commercial operation | 1/97 |

**Table 3. Milestone Schedule**

Several major milestone have been completed. These include:

- Award of SWEC engineering in July 1991.
- Award of the TRW slagging combustor, FWEC boiler, Joy scrubber and baghouse, and Sumitomo turbine-generator contracts and release of supplier engineering in September 1991.
- Initiation of a camera-based visibility monitoring program in December 1991.
- Release of the PSD permit application in April 1992.
- Completion of Phase IA of project definition, start of Phase IIA procurement, and continuation of Phase IB detailed design in July 1992.

- Start of the TRW demonstration tests of the precombustor and direct coal feed system at TRW's testing facility in California in September 1992.

- Completion of Unit No. 1 improvement modifications to facilitate the integration of HCCP with the site.

- Alaska PUC approval of the GVEA/AIDEA power purchase agreement.

Accompanied with these milestone completions, there have been several slippages. These include:

- Delayed release of the EIS being prepared by DOE.

- Structural engineering delays caused by delays of certain vendors to provide design information and to accommodate technology change.

- Engineering delays as a result of concept changes to contain and reduce capital costs.

At this time, AIDEA does not anticipate a delay in initial operation of HCCP. However the critical path activities must be maintained. The most critical activities are:

- Release of the boiler fabrication.

- Completion of the EIS and PSD.

- Start of 1993 construction, including earthworks, substructure, and adequate preliminary steel work to permit enclosure of all facilities by the end of the 3rd quarter 1994.

AIDEA firmly believes the project completion dates can be maintained. AIDEA has analyzed the associated risks with these changes and has mitigation strategies in place to contain cost, schedule, and technology risks.

## GLOSSARY

| | |
|---|---|
| AIDEA | Alaska Industrial Development and Export Authority |
| $CaCO_3$ | Limestone (calcium carbonate) |
| CaO | Lime (calcium oxide) |
| DOE | U.S. Department of Energy |
| FCM | Flash Calcined Material |
| FETS | Fossil Energy Test Site |
| GVEA | Golden Valley Electric Association, Inc. |
| HCCP | Healy Clean Coal Project |
| Joy | Joy Technologies, Inc. |
| $NO_x$ | Oxides of nitrogen |
| NSPS | New Source Performance Standards |
| O&M | Operation and Maintenance |
| SDA | Spray dryer absorber |
| $SO_2$ | Sulfur dioxide |
| SWEC | Stone & Webster Engineering Corporation |
| TRW | TRW, Inc. |
| UCM | Usibelli Coal Mine, Inc. |

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ThermoChem, Inc.

Advanced *Energy* Technology

# DEMONSTRATION OF PulseEnhanced$^{TM}$ STEAM REFORMING IN AN APPLICATION FOR GASIFICATION OF COAL

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**US Dept. of Energy**
**Clean Coal Technology Conference**
**Cleveland, Ohio**
**September 22-24, 1992**

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**Table 2. Proximate and Ultimate Coal Analysis**

| | BELLE AIR | EAGLE BUTTE | FORT UNION |
|---|---|---|---|
| PROXIMATE ANALYSIS | | | |
| % Moisture | 30.10 | 30.75 | 30.00 |
| % Ash | 5.01 | 4.57 | 5.19 |
| % Volatile | 33.20 | 33.31 | 31.60 |
| % Fixed Carbon | 31.69 | 31.37 | 33.21 |
| % Sulfur | 0.31 | 0.31 | 0.40 |
| HHV - Btu/lb | 8450. | 8350 | 8200 |
| MAF HHV - Btu/lb | 13022 | 12910 | 12650 |
| ULTIMATE ANALYSIS | | | |
| Moisture | 30.10 | 30.75 | 30.00 |
| Carbon | 48.79 | 47.99 | 47.50 |
| Hydrogen | 3.46 | 3.32 | 3.24 |
| Nitrogen | 0.70 | 0.62 | 0.62 |
| Chlorine | <0.01 | <0.01 | 0.01 |
| Sulfur | 0.31 | 0.31 | 0.40 |
| Oxygen | 11.63 | 12.44 | 13.04 |
| Ash | 5.01 | 4.57 | 5.19 |

The coal feed rate to the gasifier is 35,714 lb/hr; identical to the coal feed rate at the original site.

Section 110 - Process Water Receiving. The process water available from the K-Fuel Process is suitable for utilization in the gasifier demonstration project. This water contains a small amount of hydrocarbons and soluble organics (principally phenols) extracted from the coal as well as some particulates. The water is available at a pressure of 1150 psig and is saturated (i.e., available at 564°F).

This section of the gasification plant consists of a holding tank (V-4) for collecting the process water, two flash tanks (V-5 and V-6) that are used to produce 500 psig steam and 25 psig steam while concentrating the hydrocarbons in the water, and a filter (V-7) to remove insolubles. A schematic of this section is shown in **Figure 6.**

Water availability is one of the major concerns that must be addressed when siting a coal gasification facility in the semi-arid western United States. Availability of this process water at this site is a major benefit to the gasification demonstration. Furthermore, the hydrocarbon content of the process water is readily converted to valuable gaseous species in the gasifier, thereby improving efficiency of the system.

Section 200 - Fluidized Bed Gasifier. This section is shown diagrammatically in **Figure 7**. Major components are: the fluidized bed reactor (R-1), the multiple resonance tube pulse combustors (H-1), the steam superheater (E-2), the cyclone (V-1), a combustion air forced draft fan (F-1), and a start-up air blower (B-1).

The reactor is fluidized by steam generated in the waste heat boilers described later and superheated in E-2. Sufficient steam is injected through the distributor to provide a proper fluidization velocity (about 1.5 ft/sec.). As the coal feed dries, devolatilizes, and reacts with the steam, the nominal fluidization velocity increases to about 2.75

Thermochemical reaction of char with steam yields a process gas rich in $H_2S$, C0, $CO_2$, and $CH_4$. Higher hydrocarbons in the product gas are of very low concentration due to the steam reforming environment within the fluidized bed reactor.

The fluidized bed temperature is maintained at 1380 - 1450°F by the indirect heat supply from the immersed resonance tubes of the pulse combustion modules. Ten pulse combustion heater modules, each having 252 resonance tubes, will be provided. **Figure 8** shows the arrangement of the heater modules in the fluidized bed reactor.

The heater module consists of a refractory-lined combustion chamber, a water-cooled tubesheet, and 252 resonance tubes.

Section 210 - Process Gas Heat Recovery. This section consists of a waste heat boiler (E-3) as shown in **Figure 9.** The process gas is cooled from an inlet temperature of 1255° to 268°F. Steam at 535 psig is produced at a rate of nearly 32,500 lb/hr. This component is similar to the Process Gas Waste Heat Boiler included in the facility as originally proposed; however, it generates steam at a higher pressure.

Section 220 - Flue Gas Heat Recovery. This section consists of two waste heat boilers (E-1 and E-5), shown in **Figure 10**. Hot gas from the multiple resonance tube pulse combustor modules enters the boiler at 1600°F and is cooled to 350°F prior to discharge to the stack. Approximately 49,700 lb/hr of saturated steam at 1160 psig is generated as export steam as well as 27,200 lb/hr of 25 psig process steam for use in the gasifier.

Section 300 - Quench Venturi Scrubber. The process gas from the waste heat boiler (E-3) enters the venturi (X-1) at a temperature of 268°F and is cooled and scrubbed by direct contact with water. **Figure 11** is a diagram of this section. In addition to removing particulates, the quench venturi removes ammonia by absorption in the water.

The contact water and condensate from the process gas is cooled in an air-cooled heat exchanger (E-4). Net condensate is filtered (V-3) to remove suspended particles. The weak ammonia solution is discharged.

Section 310 - $H_2S$ Removal. Gases leaving the quench venturi enter this scrubber where $H_2S$ is removed. The Sulfur-Ox Process has been tentatively selected to perform the required sulfur removal. **Figure 12** is a diagram of this section.

By-product sulfur will be sold, if feasible. If transportation costs exceed sale price, the sulfur is sufficiently stable to permit disposal by landfill.

A portion of the clean product gas is returned to the multiple resonant tube pulse combustors to provide the heat of reaction to the fluidized bed reactor and the remaining gas is exported as fuel for electricity production.

## Commercialization Planning:

The multiple-resonance tube pulse combustor is the most flexible configuration of the MTCI pulse combustor technology. This configuration has been employed by MTCI for combustion of coal, gas and oil fuels for a variety of applications. The technology offers opportunities for high heat transfer between the oscillating flue gas flow in the multiple resonance tubes and the inner walls of such tubes.

The multiple resonance tube pulse combustor technology provides design flexibility for low $NO_x$ combustion of liquid or gaseous fuels. The combustor configuration can be used for water heating, indirect gasifier heating, air heating or steam generation employing the heat removed from the multiple resonance tubes of the combustor.

In addition, solids can be burned in the pulse combustor. MTCI employed a multiple resonance tube pulse coal combustor for clean coal firing of industrial and commercial boilers. A mixture of natural gas and raw oil shale have also been successfully fired in a pulse combustor application.

ELECTRIC UTILITY MARKET

With the enactment of the Clean Air Act Amendments, the utility sector is required to reduce the emissions from electric utility power plants significantly. The cost of compliance with provisions and regulations promulgated under the Clean Air Act will be large. While new coal utilization technologies have been under development for many years under funding by DOE and private sources, the clean Air Act will be a strong impetus for the use of such technology to meet the new environmental requirements.

The original ThermoChem proposal envisioned two time frames for application of its key technology in this market and identified specific embodiments for each time frame.

1) Near-Term Retrofit Applications

In utility retrofit applications a number of key features of the commercial embodiment of the technology were identified and discussed, as follows:

i. Low $NO_x$ and $SO_x$ retrofit coal combustors for the utility applications.

ii. Over-fired pulse combustors for $NO_x$ and $SO_x$ reduction.

iii. Induct pulse combustor systems for combined ash agglomeration/$NO_x$ reduction and sulfur capture.

2) Mid-Term Advanced Utility Systems

In this time frame, ThermoChem identified two new power generation concepts in which its technology could be deployed:

i. Fuel Cell Power Plants.

ii. Integrated Combined Cycle Power Plants.

In the submittal, each of these Near-Term Retrofit and Mid-Term Advanced systems was described and worksheets provided, in accordance with PON instructions, to identify and quantify system efficiencies and emissions.

3) Industrial and Utility Boilers

The proposal also listed the impacts that the key technology could make on industrial and utility boilers. Similar comments to those made for utility systems prevail in this case as well.

4) Other Industries

The ThermoChem proposal identified opportunities in the future industrial gasifier market as well as in related (non-coal) industries such as oil shale and pulp and paper. Again, it must be concluded that the conclusions drawn in the proposal about future commercial plans in these industries will still be served equally well.

## BENEFICIATED COAL

As can be seen from the brief summary provided above, the original ThermoChem proposal envisioned a broad range of future markets and embodiments for the key technology to be demonstrated. However, it did not describe the potential of its technology with a coal beneficiation technology as the principle use of the products. Since the beneficiation plant is not a part of the DOE project, the benefits for this or any other beneficiated coal product for that matter are not directly relevant to the proposed demonstration. However, future markets for beneficiated fuels such as the K-Fuels Process and MTCI technology do provide an avenue for commercialization of the demonstrated key technology, and this future market is relevant to the present discussion.

The Clean Air Act Amendments will have a significant impact upon Mid-western coal-burning electric utilities, many of which are excellent candidates for blending or substituting beneficiated fuels for their present coal supplies. By blending or substituting low sulfur coal for the high sulfur coals they presently burn, many of these utilities will be able to take advantage of low sulfur and low fuel nitrogen Powder River coal concomitant with the high heat content offered by beneficiation without any derating of their power generation facilities. In a recent survey of 90 utilities, Smith, Barney Company concluded that almost 40% of the utilities would use fuel switching as a means of complying with Phase I of the Clean Air Act Amendments; another 18% would utilize fuel switching as part of their compliance strategy. The commercial potential for the MTCI gasifier in this relatively near-term market was not fully appreciated in the original ThermoChem submission, but as a result of the proposed revision, the commercial prospects of utilizing the MTCI gasifier for a coal beneficiation process application are bright indeed.

To put this prospect in perspective, the 900 million tons of coal burned annually in the United States are broken down by market segments in **Table 3**.

**Table 3: U.S. Coal Market Segments**

| MARKET SEGMENT | TONS/YEAR | % MARKET |
|---|---|---|
| Utility systems not complying with the 1990 Clean Air Amendments | 200,000,000 | 22.2 |
| Industrial boilers | 150,000,000 | 16.7 |
| Utility systems currently captive to high sulfur mines which are and must use scrubbers or make strategic decisions for an alternative to scrubbers | 100,000,000 | 11.1 |
| Utility systems using Compliance Coal (mostly low-rank Western) | 250,000,000 | 27.8 |
| Utility systems currently with scrubbers | 200,000,000 | 22.2 |
| TOTAL COAL BURNED U.S/YEAR | 900,000,000 | 100.0 |

The U.S. currently has approximately 1,400 coal-fired utility boilers that are larger than 50 MW. Of these, approximately 200 are utility cyclone units requiring high Btu, low sulfur, and low fusion temperature fuel. Very limited quantities (less than 20 million tons per year) of this quality coal is currently mined, leaving the utilities who own such units with two options other than switching to or blending with K-Fuel or some other beneficiated coal product.

i. Installing scrubbers, which require large capital investment and result in increased operating and by-product disposal costs; and

ii. Retiring power generation units that still have useful life. Compliance replacement or repowering will have an increased cost per KW delivered, compared to extending the life of an existing facility.

Neither of these options is a good alternative economically for a utility or the U.S. economy.

As suggested by the Smith, Barney Report and Table 3, beneficiated coal products have a strong possibility of significant market penetration in 39% of the overall market (non-compliance utility systems and industrial boilers); a moderate market penetration possibility in the middle tier 39% (compliance coal and high sulfur captive systems); and future market penetration possibility in the currently scrubber 22% market segment. Thus, market data indicate that successful construction and operation of the gasifier for the Wyoming site should lead to significant replication. **Table 4** below shows that a large number of such plants will be needed to meet demand for even a 1% market share penetration.

**Table 4: Coal Energy Consumed by the U.S. Economy and the Number of Demonstration Sized Modules Necessary to Meet 1% Market Share Demand**

| PROJECTED U.S. DOMESTIC COAL CONSUMPTION YEAR | PROJECTED U.S. DOMESTIC COAL CONSUMPTION MIL T/YEAR | K-FUEL @ 1% MARKET SHARE MIL T/YR | PLANTS NEEDED @ 425 KT/Y PLANT SIZE |
|---|---|---|---|
| 1987 est. | 838 | 8.38 | 19.7 |
| 1990 | 893 | 8.93 | 21.0 |
| 1995 | 951 | 9.51 | 22.4 |
| 2000 | 1074 | 10.74 | 25.3 |
| 2005 | 1248 | 12.48 | 29.4 |
| 2010 | 1481 | 14.81 | 34.8 |
| 2015 | 1687 | 16.87 | 39.7 |
| 2020 | 1947 | 19.47 | 45.8 |
| 2025 | 2184 | 21.84 | 51.4 |
| 2030 | 2460 | 24.60 | 57.9 |

Each beneficiation module will require an MTCI gasifier of comparable size to that which will be installed at the new site. This represents a significant commercial market for the MTCI gasifier, especially in light of the sponsors belief that within a 10- to 20-year time period, beneficiation processes such as the K-Fuel can achieve better than a 5% penetration of the total U.S. domestic coal market. Such modules built in Alaska for export to Pacific Rim countries markets and/or built in Texas for export to other international markets could substantially increase the number of module replications.

ThermoChem's strategy for penetrating this potential market has been to agree to grant to Enserv an exclusive license for the MTCI gasifier used in conjunction with the beneficiation technology. Enserv plans to market aggressively to market segments identified, by:

> (i) identifying the targeted utility and industrial coal consumers whose immediate needs warrant the use of the beneficiation fuel, and (ii) obtaining commitments for future long-term purchases.

Enserv will focus on market segments as follows:

<u>Marketing Priority I</u>

- Facilities which:
    - have existing cyclone boiler units and require low fusion temperature fuel;
    - appear on the Clean Air Act's "worst offender" list;
    - require low sulfur, high-Btu coal; and
    - face further compliance regulation imposed under State clean air legislation.

- <u>Marketing Priority II</u>

  Facilities which:
    - are remaining plants appearing on the Clean Air Act's "worst offender" list;
    - have existing cyclone boiler units;
    - must reduce $SO_2$ emissions, which can be accomplished by using low sulfur, high-Btu coal; and
    - do not require low fusion temperature, but need premium quality fuel, such as stoker, grate, and P.C. units.

- Marketing Priority III

  Facilities which:

  - are part of the remainder of the target market affected by the Clean Air Act, as amended, or can benefit from the use of a premium quality clean coal.

Based on this strategy and their specific assessment of market opportunities, Enserv has established marketing objectives through the year 2000 as follows:

i. Prove the commercial viability of the integrated process prior to the end of the Demonstration Project in the 1st or 2nd quarter of 1996.

ii. Sell long-term fuel supply contracts to customers in the high potential 39% of total market. WP&L Company has already committed for the full output (425,000 tons/year) of the beneficiation plant for a period of 15 years. Other strategic investors may be similarly interested.

iii. Construct a large number of modules prior to the year 2000. Fifteen modules of 425,000 tons/year output can be built and operated for 20 years at the site proposed for the Revised Project. This implies that 15 MTCI gasifiers (or their equivalent) would also be built, consuming about 1.5 million tons of coal annually. Such a growth pattern would enable gasifier improvements (such as elevated pressure operation) to be installed and perfected. It would also encourage system efficiency improvements to be installed (such as IGCC cogeneration of electricity).

Based on these newly recognized commercial opportunities for the MTCI gasifiers, application to coal beneficiation technologies, and on the willingness and capability of Enserv to market the gasifier as an integrated system with the beneficiation plant.

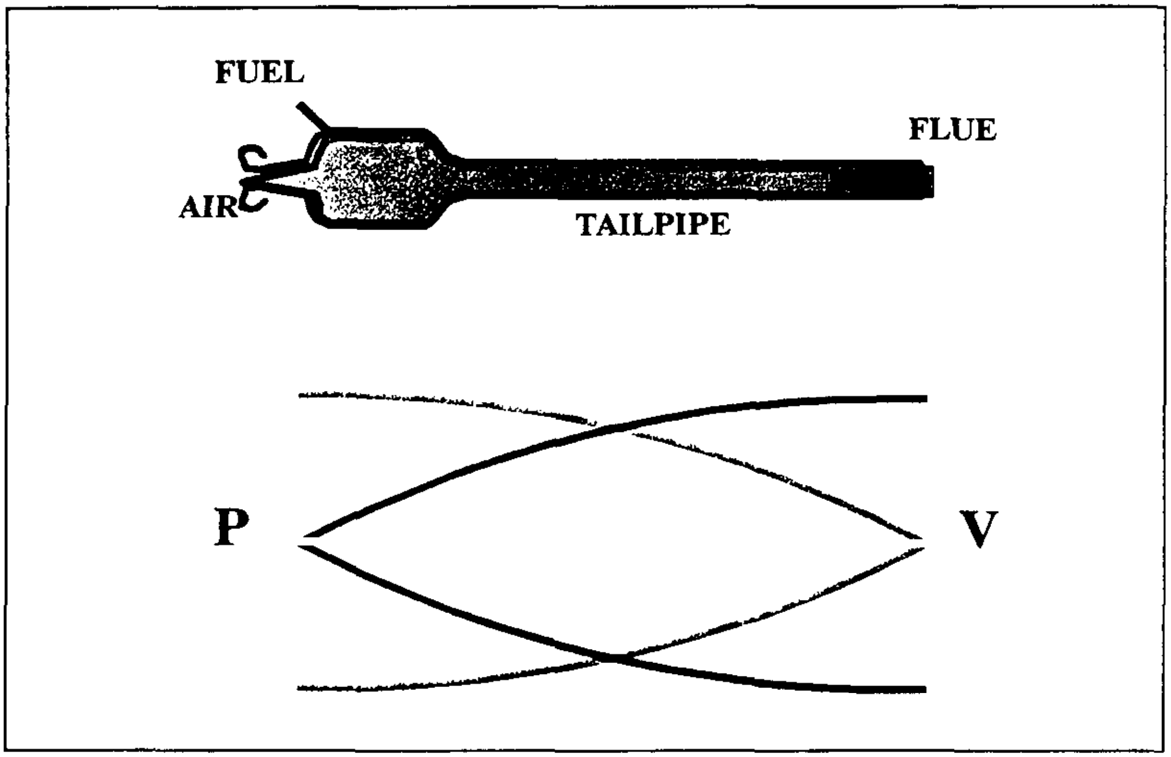


**Figure 1** **Pulse Combustion Schematic**

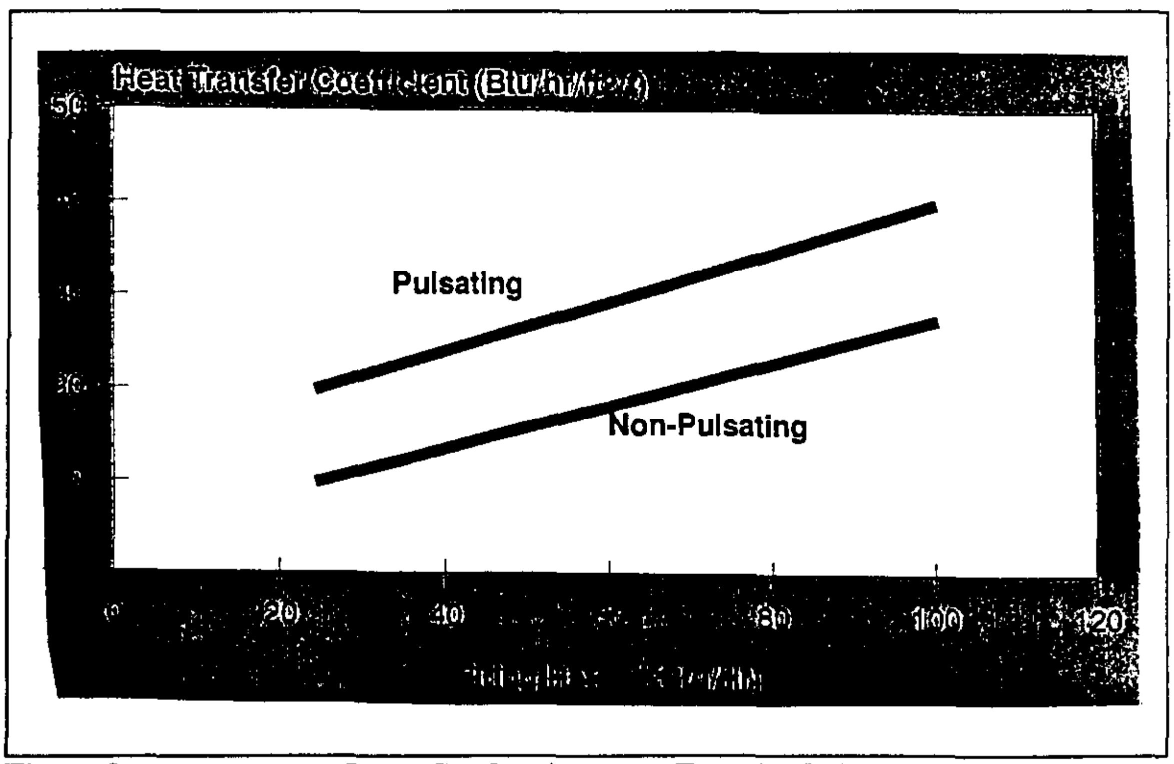


**Figure 2** **Pulse Combustion Heat Transfer Enhancement**

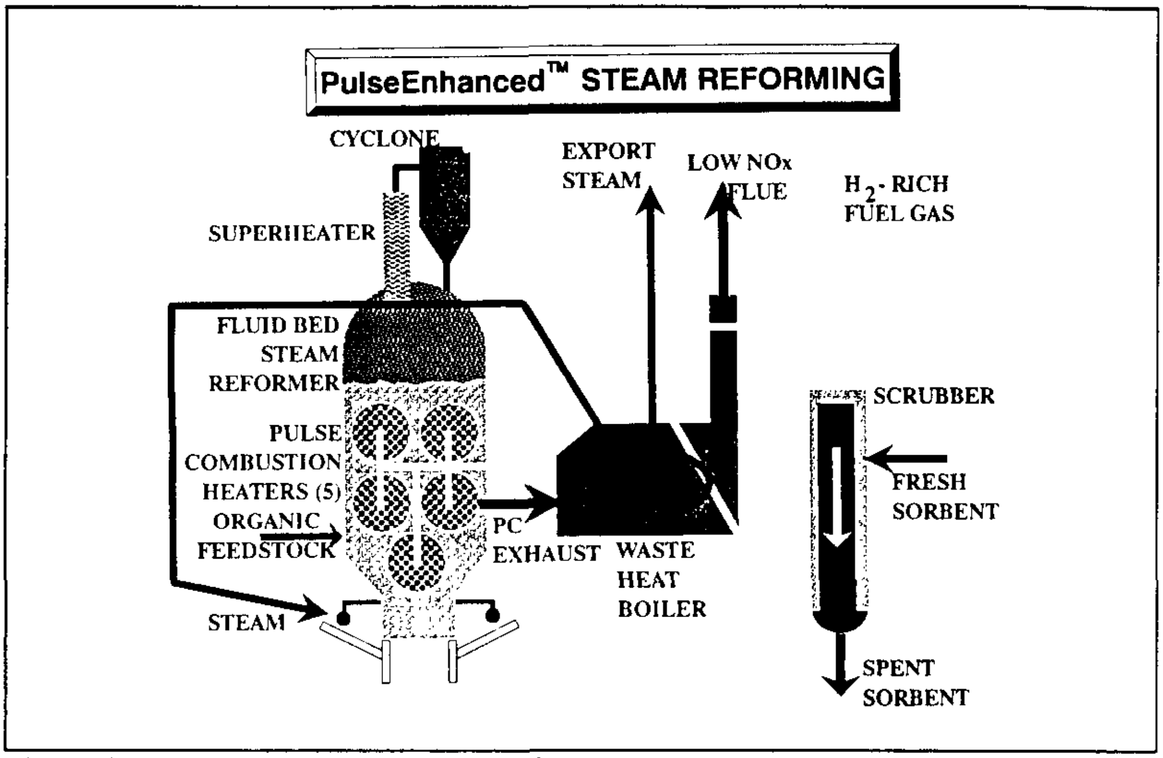


**Figure 3** **Steam Reforming Process - Basic Schematic**

| FEED MATERIAL | LIGNITE | LIGNITE | LIGNITE | LIGNITE | COAL |
|---|---|---|---|---|---|
| BED MATERIAL | LIMESTONE | LIMESTONE | SAND | SAND | LIMESTONE |
| TEMPERATURE (°F) | 1430 | 1370 | 1310 | 1430 | 1390 |
| FEED RATE (lb/hr) | 15 | 15.1 | 8.1 | 7.3 | 16.9 |
| STEAM RATE (lb/hr) | 28.3 | 30.6 | 30.6 | 28.3 | 28.3 |
| PRODUCT GAS ANALYSIS | | | | | |
| $H_2$ | 52.79 | 69.38 | 62.27 | 62.27 | 28.39 |
| CO | 31.71 | 21.47 | 6.66 | 8.83 | 28.34 |
| $CO_2$ | 12.62 | 6.14 | 27.10 | 26.47 | 12.22 |
| $CH_4$ | 2.25 | 2.40 | 3.04 | 1.76 | 3.13 |
| $C_2H_4$ | 0.33 | 0.26 | 0.29 | 0.28 | .32 |
| $C_2H_6$ | 0.12 | 0.12 | 0.19 | 0.07 | .15 |
| $C_3$ | 0.01 | 0.04 | 0.07 | 0.04 | 0.05 |
| $C_4$+ | 0.04 | 0.03 | 0.04 | 0.02 | .04 |
| $H_2S$ | 0.13 | 0.16 | 0.34 | 0.34 | .14 |
| GAS PRODUCT (lb/hr) | 31.30 | 20.26 | 16.33 | 10.96 | 24.7 |

**Figure 4** **Range of Composition of Product Gas**

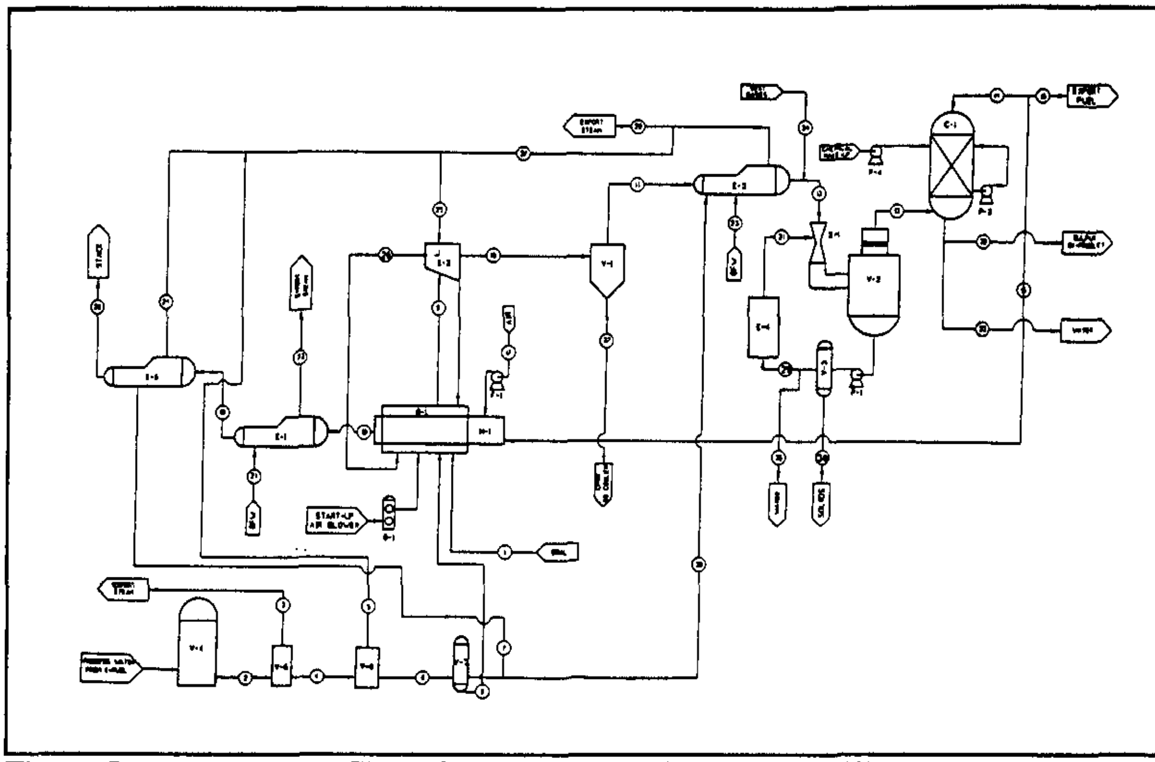

**Figure 5** **Clean Coal IV Process Schematic & Flow**

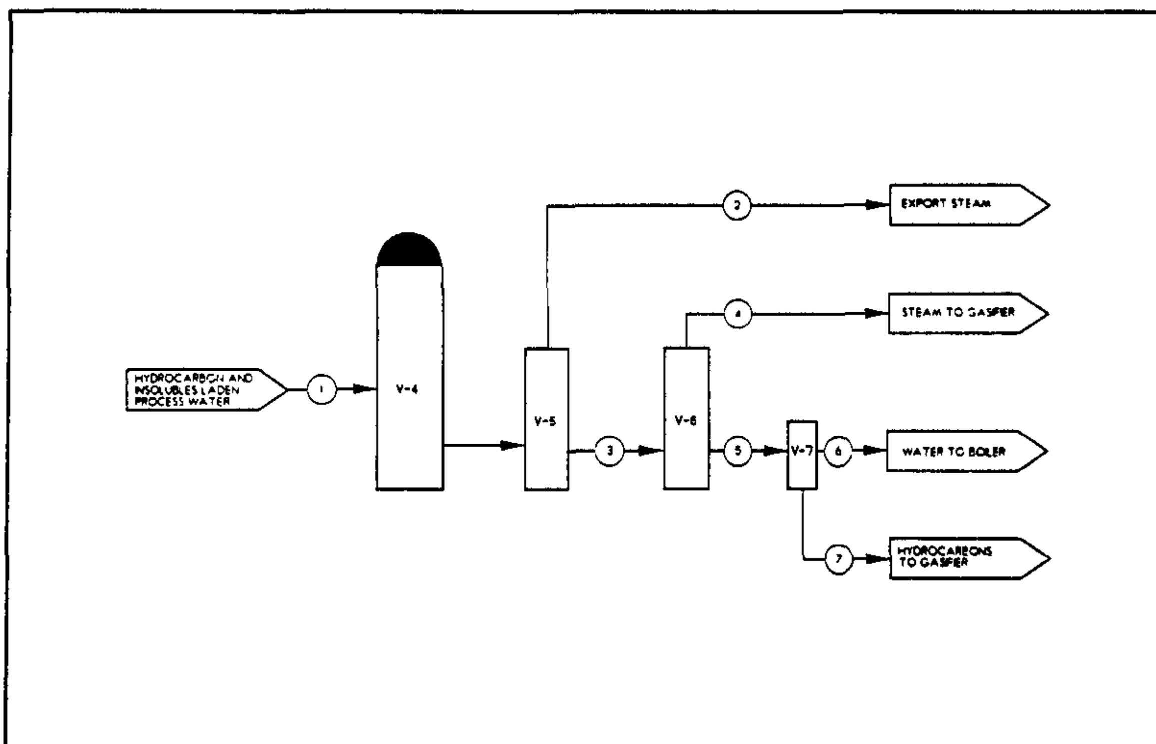


**Figure 6** **Process Water Receiving**

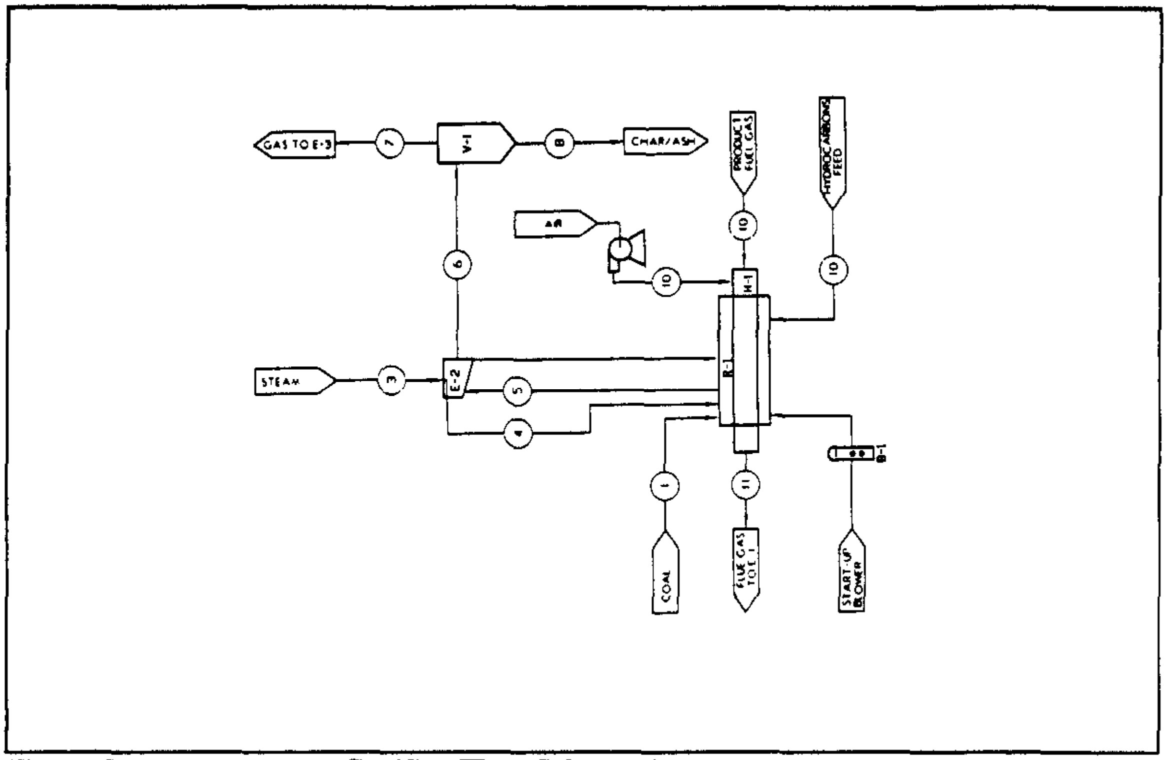


**Figure 7** **Gasifier Flow Schematic**

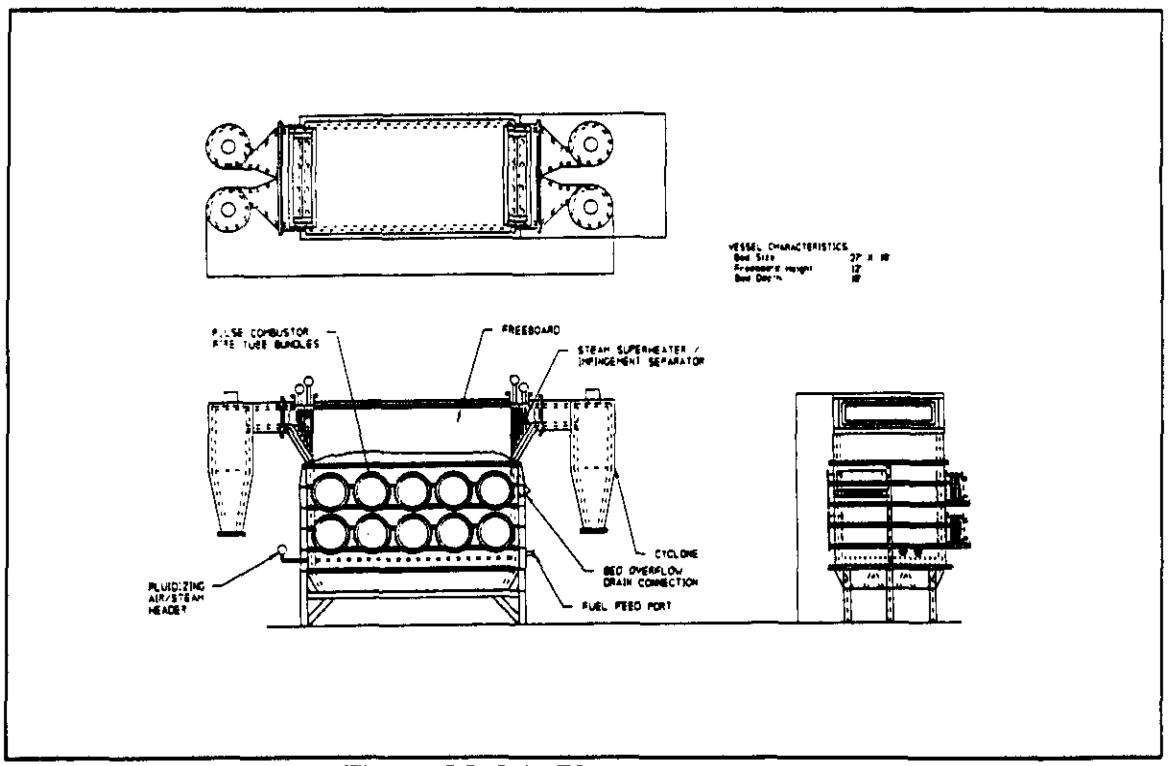


**Figure 8** **Heater Module Placement**

# COAL QUALITY EXPERT: STATUS AND SOFTWARE SPECIFICATIONS

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## BACKGROUND

General

Under the Clean Coal Technology Program (Clean Coal Round 1), the U.S. Department of Energy (DOE) and the Electric Power Research Institute (EPRI) are funding the development and demonstration of a computer program called the Coal Quality Expert (CQE™). When finished, the CQE will be a comprehensive PC-based program which can be used to evaluate several potential coal cleaning, blending, and switching options to reduce power plant emissions while minimizing generation costs. The CQE will be flexible in nature and capable of evaluating various qualities of coal, available transportation options, performance issues, and alternative emissions control strategies. This allows the CQE to determine the most cost-effective coal and the least expensive emissions control strategy for a given plant. To accomplish this, the CQE will be composed of technical models to evaluate performance issues; environmental models to evaluate environmental and regulatory issues; and cost estimating models to predict costs for installations of new and retrofit coal cleaning processes, power production equipment, and emissions control systems as well as other productions costs such as consumables (fuel, scrubber additive, etc.), waste disposal, operating and maintenance, and replacement energy costs. These technical, environmental, and economic models as well as a graphical user interface will be developed for the CQE. And, in addition, to take advantage of already existing capability, the CQE will rely on seamless integration of already proven and extensively used computer programs such as the EPRI Coal Quality Information System, Coal Quality Impact Model (CQIM™), and $NO_X$PERT.

The companies involved in developing the CQE software and their related development roles are as follows:

- ABB Combustion Engineering is co-program manager responsible for technical assistance to CQ Inc., for bench- and pilot-scale combustion testing and for development of critical CQE algorithms and submodels related to erosion, slagging, and fouling. Subcontractors supporting ABB/CE are UND Energy and Environmental Research Center and PSI Technologies.
- Babcock & Wilcox is responsible for conducting pilot-scale tests on cyclone combustors and providing test results to the development team.

- Black & Veatch (B&V) is the project's primary software developer and manager responsible for supervising, coordinating, and planning all software development efforts. They are also responsible for defining and designing the CQE user interface (look and feel), user interaction with CQE, CQE technical/environmental/economic models and capabilities, and standard applications. In addition, B&V is responsible for coding, support, and verification of the CQE program.
- CQ Inc. is managing the CQE project and responsible for evaluating the benefits of cleaning coals with different cleaning processes. This information will be used by Decision Focus, Inc. to develop coal cleaning feasibility, performance, and costing programs. CQ Inc. is responsible for coordination and supervision of development of new algorithms/models developed directly from test burn results. CQ Inc. is also responsible for development of coal handleability criteria and a predictive model.
- Decision Focus, Inc. (DFI) is responsible for supervising, coordinating, and planning software development efforts related to the Fuel Supply Expert, with deals with retrieval/storage of coal data, transportation costs, feasibility of cleaning processes, and cost predictions for cleaning facilities.
- Electric Power Technologies (EPT) is responsible for conducting field tests and supplying test results to the project team for algorithm development and program validation. Subcontractors assisting EPT in conducting the field tests and analyzing the results are Energy and Environmental Research Corporation (EER), Fossil Energy Research Corporation (FERCO), Southern Research Institute (SRI), and Southern Company Services (SCS). Utilities sponsoring the tests are as follows:
    - Alabama Power Company, Gaston Unit 5 (880 Mw).
    - Duquesne Light Company, Cheswick (500 Mw).
    - Mississippi Power Company, Watson Unit 4 (250 Mw).
    - Northern States Power, King (560 Mw).
    - Pennsylvania Electric Company and New York State Electric & Gas Corporation, Homer City Unit 2 (600 Mw).
    - Public Service of Oklahoma, Northeastern Unit 4 (445 Mw).

## Program Objectives

The primary objective of the CQE program is to provide the utility industry with a PC expert system to confidently and inexpensively evaluate the potential for coal cleaning, blending, and switching options to reduce emissions while producing lowest cost electricity. To accomplish this objective and ensure the success of this software product, a number of specific goals have been established as follows:

- Design for a wide range of users within a utility and the industry.
- Integrate knowledge and experience from the project team and tests.
- Share tools, data, knowledge, and decisions between diverse portions of the utility.
- Base knowledge and decisions on a consistent set of information throughout the program.
- Capture knowledge so it can be used in the future.
- Provide a framework for a variety of decisions.
- Provide advanced technical models capable of including complex knowledge and decisions.
- Integrate other tools used across the industry.
- Make CQE customizable for users to be able to tailor CQE to utility specific needs.
- Provide extensibility - can grow or change through time.
- Provide flexibility - easy-to-use program.
- Employ a robust programming language to allow complex analyses and yet be simple to maintain across developers.
- Design for hardware readily available to potential users and software compatibility with future changes in platforms.

## Programming Requirements/Guidelines

The CQE will be developed following guidelines designed to ensure software quality, consistency, efficiency, and flexibility.

### *Flexibility*

The CQE will be developed using object-oriented techniques which will be implemented using the C++ language. C++ adds object-oriented extensions to C. In C++, a **class** is a template that defines both the data and valid actions for an object. The class's variables are called **attributes**; the functions that are defined as valid for a class are known as its **methods**. The act of calling one of a class's methods is sometimes referred to as **sending a message** to the class. Object-oriented design creates a representation of a real-world problem and wraps it into a software solution. Unlike other methods, object-oriented techniques result in a design that interconnects data objects and processing rather than processing alone. The unique nature of object-oriented design lies in its ability to build upon the concepts of abstraction, encapsulation, inheritance, and polymorphism.

Abstraction consists of focusing on what an object is and does before deciding how it should be implemented. It involves representing the essential, inherent aspects of an object while ignoring its other properties, allowing the modeling of complex real-world objects. For example, suppose that the only properties of coal that interest us are its proximate and ultimate analyses. We will model coal as having only these properties, ignoring any others. It is also important to note that, at this stage, we are not concerned about how the coal class will be implemented.

Encapsulation (information hiding) is the separation of the external interface to the object from its internal implementation details. The external interface is accessible to other objects, the internal details are hidden from them. This technique is important in creating reliable, maintainable code; it also allows the implementation of the object to change as needed, allowing the external interface to remain unchanged. For example, the proximate analysis data stored in the coal class would be hidden from other objects. Any object wanting the proximate analysis would call a method of the coal class, GetProxAnalysis0, to retrieve the data. Because other objects interact with the coal class exclusively through the external interface functions, the programmer is free to change the way that the proximate analysis is represented in the coal class.

Inheritance is the creation of a new class of objects from a parent class. The subclass inherits all the data and methods of its parent class, and is given additional data and/or methods to extend its functionality beyond that of the parent. The subclass can, through polymorphism, be treated the same as the parent class. Inheritance allows the designer to factor out the common properties of several classes into a common superclass and to inherit these properties in the subclass, eliminating repetition within the common classes and enhancing understanding and maintainability. For example, Ash Handling Systems, FGD Systems, and Particulate Removal Systems will each be derived from the Equipment

System class. The subclasses will add additional data and methods and redefine inherited methods as appropriate.

Polymorphism allows the same operation (message) to have different effects on different classes, as appropriate. Polymorphism is tied to inheritance; each subclass may re-implement an inherited method when appropriate for that subclass. Continuing the previous example, polymorphism allows an instance for the FGD System class to be treated as an instance of the base Equipment System class. The base class, Equipment System, will have a method to calculate the auxiliary power required for the system. Each of the subclasses will redefine this method to correctly calculate the auxiliary power required for the particular equipment system that it is modeling.

*Consistency*

The CQE will be developed for '386/'486 machines with OS/2 Version 2.0 and Presentation Manager, but with the philosophy of being as platform independent as possible. This will be accomplished by confining OS/2 specific code to base classes and isolated areas. A small amount of effort spent up front in development will greatly ease a future port to another operating system in addition to making the CQE more reliable and easier to maintain.

*Efficiency*

The CQE will be developed using proper techniques to ensure reusability, extensibility, robustness, and consistency. Detailed guidelines are stated in Subsection 3.2 In general, strict adherence to the technique of encapsulation, the proper use of inheritance, and other object-oriented techniques will enhance the reliability and maintainability of the CQE.

*Quality*

High-quality tools are essential to the development of the CQE. Several types of tools have been identified for use in the development cycle: object-oriented design tools, C++ compilers, C++ class libraries, graphical user interface development tools, object data base management systems, and expert systems.

User Interface Requirements

Because CQE will be dealing with a large amount of data using a number of specialized applications, it is important that the interface to the program be very user-friendly, yet sophisticated enough to address each application's needs. The OS/2 operating system will provide the means for creating such an interface because of its Presentation Manager (PM) graphical user interface platform. The general "look and feel" of the CQE will be based upon standards such as IBM's Common User Access (CUA) standard and EPRI's EPRIGEMS standard. It will also be based upon comments from users of current programs such as CQIM and ARA, and from CQE test users.

The CQE user interface will employ graphical screen elements such as windows, menus, and dialog boxes. These will enable a vast amount of information to be displayed in a logical, consistent manner. In addition, icons and graphical elements will be used to further enhance the CQE interface. Tables, graphs, and other graphics will round out the CQE user interface.

User access profiles will be used to determine user preferences and privilege levels. Users will be assigned to any of a number of pre-defined or user-defined categories by the System Administrator. These categories are used to define the privilege levels for each user. Privilege levels will be set for a number of different areas and tasks in the program. Five different privilege levels are available for each area: None, Low, Medium, High, and All.

Once their privilege levels are set up by the System Administrator, individual users will be able to set up their own preferences with respect to their amount of experience with each particular portion of the program. Three levels are available--Novice, Intermediate, and Expert--with different levels of additional help and complexity.

Functional Requirements

The CQE will be composed of several elements employing the latest advancements in computer hardware, software, and programming languages. One of the biggest challenges in developing a useful and functional CQE lies in the integration of these advanced techniques into a single functional system. Realizing that several techniques will be implemented and that several autonomous program boundaries will be crossed, the program must still appear to the user as one seamless, easy-to-use program. Therefore, based on these criteria, the goals of CQE (from the user perspective) will be to develop an extremely easy-to-use program that provides direction, guidance, assistance (in the form of instant on-line, context-sensitive help), and on-screen/off-screen presentation results pertaining to practical and specific problems. To accomplish these goals, the following programming techniques, specialized software, etc. will be used.

- An expert system to provide logic control for program flow and decision-making capability.
- Specialized and uniquely designed objects.
- Advanced GUI presentation techniques including on-screen text and unit conversion manipulation.
- Specialized tools to display information and instruction from a visual perspective.
- An object data base to store and retrieve pertinent data (as well as objects).
- An Interactive Output Utility (IOU) for presentation of standard and customizable output.
- On-line help to assist the user in using and understanding the program.
- Error handling to assist the user in diagnosing and detecting problems when they arise.

## Program Documentation

Documentation for the CQE program will be prepared consistent with standards for high quality and completeness to ensure usability and credibility within the industry. The documentation will provide complete instructions for program use, detailed descriptions of calculations and examples of results. Documentation for the CQE will include a Program Usage Manual, a Program Theory Manual, and a Validation Test Cases Report. The Program Usage Manual will be the primary reference for user assistance in using all parts of the CQE. The Program Theory Manual will provide detailed descriptions of technical models and calculations within the program. The Validation Test Cases Report will document results of the host utility testing and program validation.

## Development Schedule

The CQE development schedule has been constructed to provide a structured, logical software development approach that allows timely, efficient interaction of all parties involved. Because many activities are closely related, timing of critical activities is extremely important to subsequent development efforts and successful completion of CQE within the budgeted schedules. The budgeted development schedule is extremely ambitious, considering the number of activities to be completed and the timing and interaction required of the different developers. Several software development meetings will be conducted to facilitate the development effort, meeting schedules, and improve communication. These meetings will allow project participants involved with bench, pilot, and field testing as well as software development to share ideas, concerns, and solutions to problems which can be integrated into a successful CQE product. Basically, CQE development activities can be categorized into the following four groups:

- Development of CQE applications, subapplications, and objects.
- Development and prototyping of new algorithms and experts.
- Technical improvements to existing software, mainly CQIM enhancements.
- Design/develop the "look and feel" of the CQE user interface.

Development activities for each group are expected to be concurrent. Parallel efforts will concentrate on application development, object development, user interface, and technical enhancements. Some of the major milestones or accomplishments for each year are briefly summarized below.

<u>1991</u>

- Begin Conceptualization and Preliminary Design of the Boiler and ESP\ Experts.
- Begin Evaluation of Software Development Tools.
- Develop Bulk of Preliminary CQE Software Specification Document.

<u>1992</u>

- Select Software Development Tools (February/March).
- Develop Functional CQE Prototype (late).
- Issue CQE Software Specification.
- Conduct CQE Product Definition Workshop (Fall).
- Reissue Refined Specification (Fall).
- Initiate Tech Transfer Activities.

<u>1993</u>

- Complete Application, Subapplication, and Object Development.
- Complete CQIM Enhancements.
- Develop CQE Alpha Release.

1994

- Complete New Plant Design.
- Begin Writing CQE User's and Theory Manual.
- Develop Beta Version and Beta Test Program.

1995

- Finalize CQE Documentation.
- Write Test Case Reports.
- Announce CQE Commercial Release and Conduct Workshop.

Quality Assurance

Quality assurance will play an important role in the CQE project. Quality assurance for CQE is significant because of the nature of CQE (diverse models, complex logic, interrelated tasks, large program) and because of the need, with the ambitious project schedule, to minimize the high potential for programming errors and oversights. The CQE will also place extra demands on quality assurance because of the number of companies involved in the development effort.

## USER NEEDS

The Coal Quality Expert, or CQE, will be a comprehensive analytical/ planning tool to consider the myriad of potential coal quality related purchase, operational, and planning decisions now facing the utility. Coal purchase decision processes to be supported include assessment of fuel switching, blending, coal beneficiation, and the installation of retrofit emission controls. Operational decisions to be supported focus on analysis of current unit and equipment performance to "separate" coal quality effects from operation and design influences; the CQE will also extend its umbrella to cover the various aspects of test burn planning and analysis--by evaluating "needs," helping plan test burn programs, and analyzing test burn results. Planning decisions to be supported are centered about coal quality's impacts on unit and system generation costs and emission rates; the CQE will feature specialized software modules designed to help the utility manage the complex "allowance-based" $SO_2$ emissions control program introduced in the 1990 Amendments to the Clean Air Act.

The CQE will be built on the foundation of proven, validated models to the maximum extent possible, including EPRI's Coal Quality Impact Model (CQIM), a state-of-the-art computer model designed to evaluate cost/performance impacts of fuel switching at existing power plants. However, the CQE focus is ***FLEXIBILITY***.

- ***FLEXIBILITY*** to address the engineering and analytical needs of fuel purchasing specialists, engineers, operation support staff and planners.
- ***FLEXIBILITY*** to perform its many "calculations" tailored to the needs of the specific audience and specific problem in question.

To achieve the necessary flexibility, the CQE will be built on a specialized software "architecture," utilizing current state-of-the-art programming techniques, and feature specialized software interfaces to other existing or future software products. Development of such an architecture is quite important to the ultimate success of the CQE; necessarily complex due to the complexity, variety and size of problems to be solved; and, is, therefore, the principal subject of attention in the CQE Specification. Without such an architecture, it would not be possible to meet CQE design objectives, effectively coordinate the results or analytical capabilities of other programs, let alone, to develop synergy among appropriate software modules.

To ensure the success of this software product, a number of additional objectives have been established to assure program usability, acceptability, and general functionality. Each of these objectives are highlighted and discussed below.

## Development Guidelines

### *Design for a Wide Range of Users within a Utility and the Industry*

The CQE has been designed to facilitate day-to-day use by various specific target audiences in the utility industry. As shown in Figure 2-1, the CQE will address different types of users from several branches of expertise. This target audience extends beyond the current CQIM audience, which typically includes the bottom three categories--the engineering, production, and fuel supply departments. The targeted audience for CQE is to include marketing, environmental, systems planning, and management portions of the utility in addition to the typical CQIM audience.

The program will be designed to be easily used by each of these diverse parts of the company with their needs, backgrounds, and expectations incorporated into the design. In other words, the CQE will understand the knowledge of each type of user and will respond to different types of questions and analysis needs.

*Share Tools, Data, Knowledge, and Decisions Between Diverse Portions of the Company*

Extending use of the CQE to a varied group of users assures that appropriate CQE "coverage" is realized within the utility; this is due to the fact that, by nature of the CQE's "problem set," requires large quantities of complex, varied, and utility-specific data. Therefore, extending CQE coverage within the utility will facilitate both:

1) Collection/entry of data--different users will be able to supply different types of data, thus collectively providing a consistent and accurate source of data.
2) Sharing of data/knowledge--the CQE can become a strategic communications/analysis device within the organization by facilitating the sharing of pertinent, timely, and accurate data within the utility.

Thus, the CQE will be designed to facilitate sharing of data <u>and</u> knowledge by utilizing one consistent set of tools, data, and knowledge/expertise for each CQE user, regardless of "type" of user or analysis. Such capability will also promote staff efficiency in the decision making process.

*Utilize Object-Oriented Data/Code Model*

The CQE architecture will be based on the use of the object-oriented programming (OOP) model. OOP facilitates modeling of complex problems by simulating "real life" more closely than traditional problem decomposition techniques. Unlike decomposition techniques where the specific "problem" is decomposed into smaller "problems," OOP relies on specialized libraries of data/analysis "objects" which can exhibit and understand behavior pertaining to the object in question. OOP solves problems by collecting and assimilating knowledge via consultation with applicable objects; hence, by altering order, type, and content of queries to these objects, different problems can be solved. Thus, OOP promotes "reuse" of objects and is the basis for meeting CQE flexibility requirements.

*Base Knowledge and Decisions on a Consistent Set of Information Throughout the Program*

The CQE will feature a comprehensive data model which structures all design, performance, economic, and CQE-derived "results" into a complete and consistent "view" of the data. This model is based on the premise that data is stored only once in the model and, as such, there exists only one source of data for any particular piece of information, using the object data model. Similarly, all knowledge, expertise, engineering modeling, etc. for a particular subject, device, or analysis will be "stored" in one place within CQE. This will ensure that results, advice, and other outputs will be consistent regardless of the type of application. Without this consistency, the program will be deemed inaccurate, untrustworthy, and be difficult to debug.

*Capture Knowledge So It Can Be Used in the Future*

All decisions and results will be stored with the input data which created it (storage of objects) so that such information can be re-used. The re-use of such data will minimize the need to rerun an analysis or even specific equipment models. This capability will decrease computational time, provide data for more alternatives with minimum effort, and provide a record of historical data and decisions.

*Provide a Framework for a Variety of Decisions*

The CQE is being designed, as discussed above, for use by several different types of users which will need to address a wide variety of complex issues, or analyses, some of which are complicated in nature and very difficult to understand. These complex analyses will require several sources of knowledge, expertise, operational data, and specialized computer programs if the problem is to be solved effectively in a timely manner. Figure 2-2 shows, in general, how this complex problem solving process will be viewed within CQE. As can be seen from this figure, there are several existing models and sources of expertise (or information) that will interact in a synergistic fashion such that "real world" problems can be solved. Such models will be encapsulated in CQE "objects" to allow CQE to take advantage of such models and to transform "type" of analysis available within such tools to that required of the CQE (e.g., consultation, address only specific issues, etc.).

*Provide Advanced Technical Models Capable of Including Complex Knowledge and Decisions*

The CQE will include state-of-the-art technology to provide guidance and make decisions on complex matters. The technology will include advances in industry understanding in certain areas, such as slagging and fouling, and will make use of expert systems as appropriate.

*Integrate Other Tools Used Across the Industry*

The CQE will use the best models and methods in the industry, as available to the project. Employment of industry standard programs and tools will also simplify use by the industry because tools which they are already using and wish to continue to use will be used within the program. This will also promote program acceptance by maintaining a uniform set of "results" for CQE and other tools.

*Make CQE Customizable for User to be Able to Tailor CQE to Utility Specific Needs*

The analytical capabilities of the CQE will be developed to allow for customization. The user will be able to develop different analysis methods by combining the various analytical tools available to either modify pre-built CQE applications or to develop user-specific applications to solve "other" problems. This capability will be available by "marrying" a rule-driven application framework to the CQE library of objects and subapplications. In a similar manner, OOP technology being employed will also provide a mechanism for each replacement of specific objects and models to allow user-specific models to be incorporated.

*Provide Extensibility - Can Grow or Change through Time*

The CQE will be designed such that future modifications can be easily made to enhance or replace current models. This objective will be accomplished by judicious application of object-oriented programming and maintaining an eye toward current or future related R&D efforts.

*Provide Flexibility - Easy-to-Use Program*

The CQE will be designed to be both easy to use and flexible in application. The program will be logically organized to enhance understandability and speed location of needed data or analyses. The CQE will include knowledge-based help which will provide guidance in program usage and definitions, ranges, etc. for input data. The help will be sensitive to the type and capability of the specific user to provide help consistent with user needs. Program output will be user-definable, as much as practical. That is, formatting of selection of results on printed results will be selectable by the user. Interactive, on-screen results will also be provided. These interactive results will include graphical results with the capability of selecting particular portions of a bar graph and having back-up information, data, or explanations appear on screen.

*Employ a Robust Programming Language, C++, to Allow Complex Analyses and Yet Be Simple to Maintain Across Developers*

CQE programming will employ C++, a popular, growing industry standard language which can readily support the complex nature of the program being developed. C++ supports all necessary OOP capabilities; existing, non C++ applications will be incorporated via encapsulation in specialized CQE server objects. C++, via class libraries (purchased and developed for CQE) can also support parallel development by programmers within various companies. OOP provides for rapid prototyping to support parallel development, demonstration and general design, and Beta releases.

*Design for Hardware Readily Available to Potential Users and Software Compatibility with Future Changes in Platforms*

The CQE will be developed for '386 or '486-based PC systems, under IBM OS/2 2.0 operating system, or based on current hardware/software standards available to the majority of potential users. By judicious software design (encapsulate platform specific code in limited objects/procedures) and use of the appropriate development tools will also allow for transport to future platforms, should such a need arise.

The program must be designed in such a manner that the CQE can take advantage of advances in OS/2, PM, C++, or hardware to extend product "life"; in this manner, the CQE will not become obsolete shortly after commercial release but can continue to remain viable for the next 10 to 20 years, without significant retooling.

*Integrate Knowledge and Experience from the Project Team and Tests*

During the development phase of the CQE, significant insight regarding coal quality, operational, and design effects are being gained by the project team through in-depth testing and analysis. The CQE will capture knowledge available from the testing, analysis, and available from the engineering team assembled for the project. Much of this knowledge is expected to significantly expand the envelope of understanding in the industry. The CQE will also have the ability to employ pilot, bench, and field test data within the analyses performed.

## APPLICATION

The Coal Quality Expert is a personal computer based expert system comprised of more than 20 sub-models designed to predict the impact of coal quality upon power plant operations, maintenance, economics, and emissions. The CQE will permit utilities to purchase the lowest cost clean coals tailored to their specific requirements. The CQE will be flexible enough to support the development and evaluation of high level strategies for compliance with key requirements of the 1990 Clean Air Act Amendments, such as estimating the potential contributions of coal cleaning, fuel switching, and retrofit options to meet overall $SO_2$ targets. In addition, the CQE will provide detailed modeling and analytical support needed for evaluating specific options, such as an FGD retrofit decision for a specific plant.

By integrating more than 20 computer models and databases into a single tool, the CQE will enable utility planners, engineers, and manager to examine the costs and effects of coal quality on each facet of power generation--from the mines to the stacks. The CQE will allow users to define and compare a wide range of scenarios by combining alternative source coals, transportation options, coal cleaning options, emission control alternatives, and plant design and modification decisions. In addition, the CQE will be an important asset to electric utilities and coal producers as they conduct their business in this climate of economic and regulatory uncertainty, increasing environmental pressure and technological expansion. An advanced user-interface, expert system capabilities, and an object-oriented software environment will allow users to readily access the necessary tools and data within the CQE to perform complex, integrated analyses easily and efficiently.

## STATUS

The CQE project is scheduled for completion in August 1994 with approximately 60 percent of the project being completed. The project consists of two major activities: (1) testing and data gathering, which involves optimization of coal quality for combustion in different types of coal-burning utilities; and (2) the development of a coal quality expert system. The major accomplishments include:

1. The most significant accomplishment to date was the commercialization of the Acid Rain Advisor (ARA) which is an easy-to-use software product designed specifically to assist the user in managing Clean Air Act compliance evaluations.
2. Three and one-half out of six field tests have been completed.
3. Three pilot-scale tests have been completed.
4. Specifications have been developed for the CQE.

There are a number of specific areas within the CQE which will make it unique:

1. Slagging and Fouling: To improve the slagging and fouling capabilities of the CQIM, algorithms will be developed to relate coal properties, boiler design, excess air, sootblowing effectiveness, carbon loss, and operating conditions. Recent work performed at the University of North Dakota and at Physical Sciences Incorporated has provided a more fundamental approach to slagging and fouling that uses Computer Controlled Scanning Electron Microscopy (CCSEM). The CCSEM-based approach to predicting slagging and fouling predicts the fate of mineral species as they travel through the boiler. In addition, recent correlations done at the University of North Dakota indicate that it is possible to infer the CCSEM data from conventional ASTM analyses, thus allowing those who do not have CCSEM data on their coals to benefit from the CCSEM-based slagging and fouling estimates.

2. Boiler/ESP Experts: Historical utility experience and CQE pilot-scale and field tests have shown that the operation and performance of ESPs is strongly dependent on the properties of the coal being burned as well as the mechanical characteristics of

the specific ESP equipment. CQE's ESP Model will use expected changes in ash resistivity and past performance data to accurately predict the impacts on precipitator performance of changes in coal quality. The ESP model will have enough sensitivity to predict changes in performance as a results of small alterations of coal properties, such as those resulting from coal cleaning. Additionally, the model has correlations and procedures for predicting plume opacity as a function of particulate properties and concentrations.

3. Coal Purchase and Transport Models: One of the major areas identified by utilities as a desirable option for the CQE would be to include a Coal Purchase and Transport Model. The Coal Cleaning Optimizer and the Coal Cleaning Cost Model complement each other. They will provide coal quality and cost information for upgrading coal using physical coal cleaning technologies. This will include estimating the performance of standardized coal-cleaning flowsheets using a relationship between theoretical yield from coal washability data and the organic efficiency of a given flowsheet for a coal of a known difficulty of cleaning.

   The Coal Transportation Model covers the transportation network of rail, truck, barge, or ship, alone or in any combination in order to find the best way of transporting coal from a shipping point to a receiving point. It also covers the transfer costs and owned equipment costs. The Coal Transportation Model will allow user to define alternative transport routes and modes and evaluate the cost and risks associated with each option.

   The Coal Blending Model and Coal Handling Model also complement each other. The blending model will tell the user how to blend coals to gain the right properties for use in a specific boiler. This is especially important when blending coal for environmental compliance. The handling model will tell power plant coal handling operators if a certain coal will cause handling problems such as arching in silos or pluggage at transfer points.

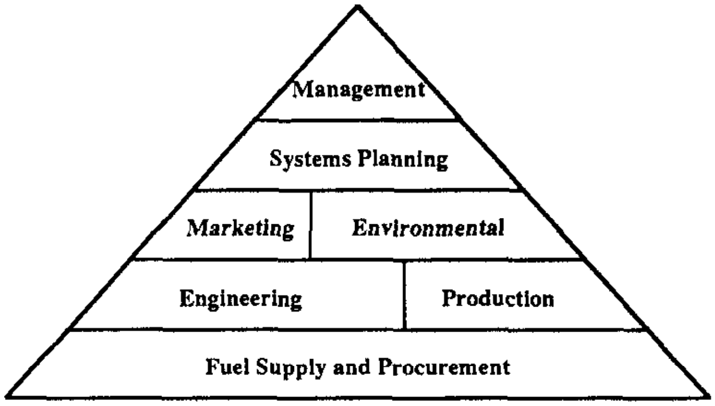


*Figure 1. Anticipated CQE Users*

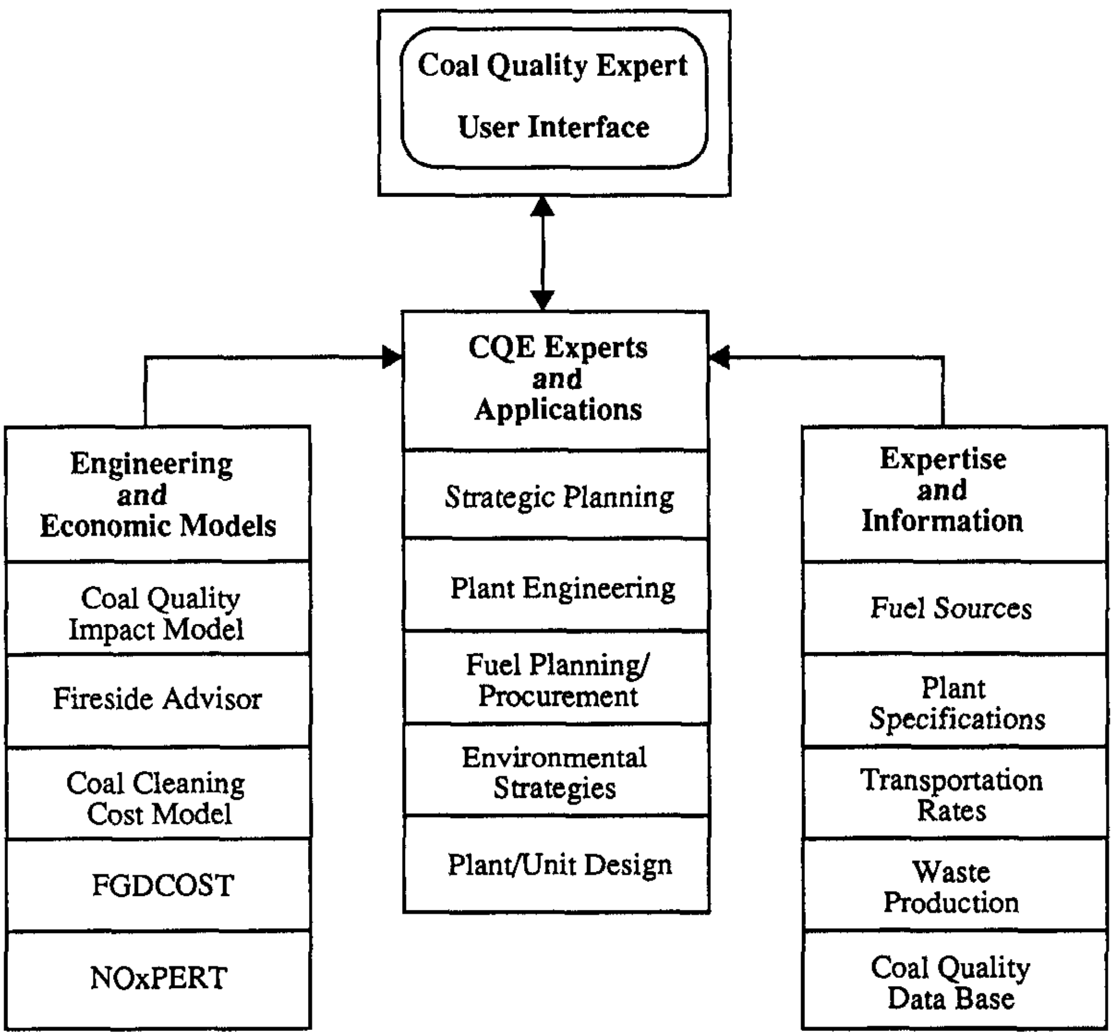


**Figure 2. Coal Quality Expert Program**

# SELF-SCRUBBING COAL: AN INTEGRATED APPROACH TO CLEAN AIR

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## ABSTRACT

The Custom Coals advanced coal cleaning plant will be designed with a unique blending of existing and new processes to produce two types of compliance coals: Carefree Coal and Self-Scrubbing Coal. Carefree Coal will be produced by cleaning the coal in a proprietary dense media cyclone circuit utilizing fine magnetite to remove up to 90% of the pyritic sulfur and correspondingly greatly reduce the ash.

While many utilities can achieve full $SO_2$ reduction compliance with Carefree Coal, others face more stringent requirements due to the higher sulfur content of their existing fuel supplies. For these circumstances, a patented Self-Scrubbing Coal will be produced by taking Carefree Coal and pelletizing limestone with the finest fraction of the clean coal. These technologies will enable over 150 billion tons of non-compliance U.S. coal reserves to meet compliance requirements.

## INTRODUCTION

Approximately 65% of all coal shipped to utilities in 1990 was above 1.2 lbs $SO_2$/MMBtu. Even though most of that coal has been cleaned in conventional coal preparation plants, it still does not meet the $SO_2$ emission limitation the Clean Air Act Amendments mandate for the year 2000. Most utilities have announced compliance plans involving either switching to lower sulfur coals from central Appalachia or the Power River Basin or the installation of scrubbers. Fortunately, for those of us attempting to commercialize clean coal technologies, relatively few long-term decisions have been made in Phase I - i.e. fewer scrubbers are scheduled than initially expected and new coal contracts rarely extend beyond the year 2000.

Through new coal preparation technologies, two compliance coal products can be produced by Custom Coals International (CCI) from most of the non-compliance coals east of the Mississippi River. They are termed Carefree Coal™ and Self-Scrubbing Coal™.

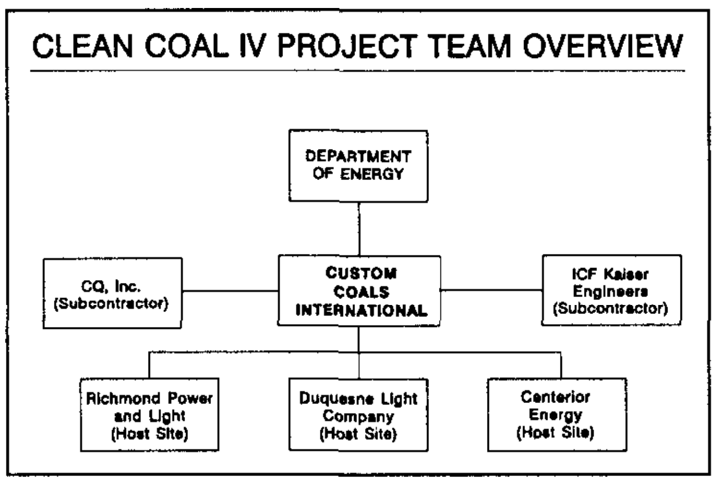
- Carefree Coal is produced solely through aggressive removal of ash and pyritic sulfur from non-compliance bituminous coal feedstocks. Carefree Coal is composed of coarse coal, fine coal and ultra fine coal. Some of the ultra fines may be agglomerated.

- Self-Scrubbing Coal contains aggressively beneficiated coal with limestone. It is comprised of coarse coal, fine coal and agglomerates. The additives are agglomerated with the ultra-fine clean coal for convenience in handling.

  For Self-Scrubbing Coal, the reduction of sulfur to compliance levels occurs in two stages. Pyrite, an iron-sulfur compound, is first removed by aggressive coal beneficiation. Sulfur dioxide, generated in the boiler from the coal's organic sulfur and residual pyritic sulfur, is then captured by the limestone. The aggressive coal beneficiation step reduces the ash content of the clean coal enough to offset sorbent addition, avoiding overloading the boilers' particulate control system.

Carefree Coal and Self-Scrubbing Coal meet the year 2000 sulfur dioxide limitations. They are derived from local coals and, therefore, are compatible with the boiler; they are priced competitively with compliance coals imported into the local region; and no capital investment is required by the utility. The net effect of CCI's technologies is that they revalue many noncompliance reserves to compliance reserves.

The objective of our Clean Coal Technology program is to design and construct a 350 ton per hour coal cleaning plant equipped with CCI's unique and innovative coal cleaning technology which will produce competitively priced compliance coals. These coals will then be test burned at three commercial utility power plants to demonstrate that these coals can meet the Clean Air Act Amendment sulfur reduction requirements.




Custom Coals, which has overall project management responsibility, has assembled an exceptional team for this project. ICF Kaiser Engineers, which will design and construct the demonstration plant, is one of the country's leaders in energy-related engineering and construction. CQ Inc., which will test and operate the demonstration plant and manage the power plant field tests, is a recognized authority in coal cleaning plant design, testing, operation and utility coal quality issues. A project management committee of senior executives from the participating companies will oversee project progress and performance.

The project costs and timetable are shown below. The preparation plant will be located in Somerset County, Pennsylvania. The host sites for the test burns are located in Richmond, Indiana, Cleveland, Ohio and Pittsburgh, Pennsylvania.

| | Dates | Proposed Costs |
|---|---|---|
| *Pre-award* | October 1991 - October 1992 | $736,969 |
| *Project Definition* | November 1992 - April 1993 | 2,000,000 |
| *Design & Engineering* | May 1993 - June 1993 | 17,567,655 |
| *Construction* | July 1993 - March 1994 | 40,116,874 |
| *Operation* | April 1994 - September 1995 | 21,304,848 |
| | **TOTAL** | **$81,726,346** |

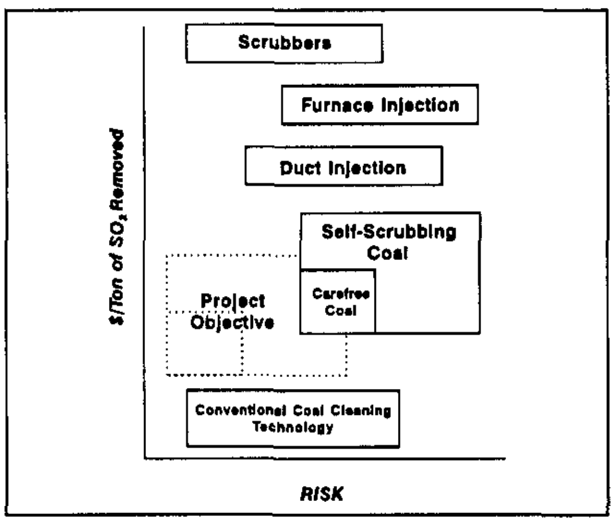
## HISTORY OF TECHNOLOGY DEVELOPMENT

The Carefree Coal and Self-Scrubbing Coal technologies were developed through the proof-of-concept stage by Genesis Research Corporation, a small research and development company headquartered in Arizona. Dr. James Kelly Kindig, the inventor of the technology, had begun work on the technology in the late 1970's. A concerted effort to develop the products for commercial use began in the early 1980's. Funding during this stage of development was provided by equity raised from individual investors.

In 1988 Duquesne Light Company agreed to fund pilot scale testing of the technology. Cleaning tests in 2-inch cyclones were performed at CQ Inc. and small-scale combustion testing occurred at Energy and Environmental Resources. The pilot scale test results supported Genesis Research claims of being able to reduce sulfur levels by up to 80%.

Given the encouraging pilot scale test results, in 1990 Duquesne agreed to fund commercial scale tests. Throughout 1990 and early 1991, a $2 million test program was conducted and documented. All unique aspects of the coal cleaning technology were tested at commercial scale equipment sizes at CQ Inc. Fine magnetite was prepared by Hazen Research, the cyclones of unique design were manufactured by Krebs Engineers and the magnetite recovery scheme was tested by Eriez Magnetics. The coal cleaning results in 10-inch cyclones substantially duplicated the performance achieved in the earlier 2-inch cyclone work. Combustion testing in 600,000 Btu/hour boilers at Energy and Environmental Resources also confirmed the earlier smaller scale results on sulfur capture in the boiler.

The full-scale demonstration provided by the Clean Coal Technology Program will provide the opportunity to blend all of the innovative aspects of the technology and prove the effectiveness of Self-Scrubbing Coal in reducing emissions. The demonstration will also prove the cost-effectiveness of the technology, paving the way to full commercialization of Self-Scrubbing Coal.



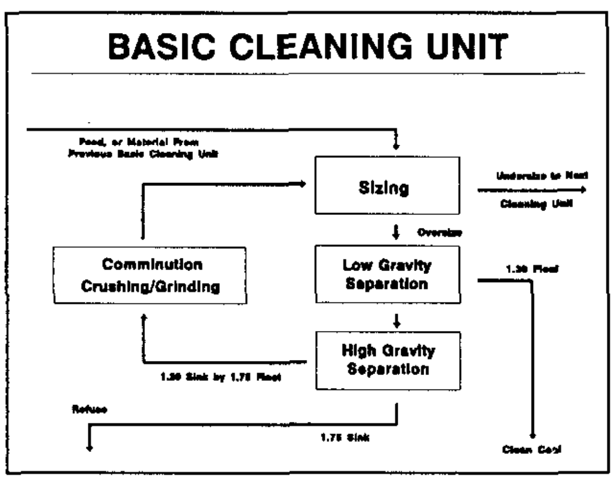

## TECHNOLOGY DESCRIPTION

Raw coal may be viewed as an aggregation of three basic types of components [See Figure 1]. They are organic material, pyrite and rock. Each of these three materials is found free in raw coal. A large portion of raw coal, however, is comprised of two or all of these components locked together. It is this locking that creates the spectrum of specific gravities characteristic of coal.

Most conventional coal cleaning partitions raw coal into two components: one less-than and the other greater-than some pre-selected specific gravity [See Figure 2]. Clean coal, the former, contains both free and locked particles. The locked particles, unfortunately, carry sulfur (from pyrite) and ash (from rock) into the marketable clean coal product. The refuse also contains both free and locked particles. Locked refuse particles contain organic material that constitutes a loss of coal (heating value) and, for the producer, a loss of revenue.

Locked particles are first isolated in the Carefree process [See Figure 3]. These isolated coarse locked particles are crushed to produce smaller particles. This is a major factor distinguishing the Carefree process from conventional coal cleaning. Most of the smaller particles are essentially free, depending upon the nature of the coal. The Carefree process embodies an efficient method for separating the large quantity of smaller, relatively free particles into clean coal and refuse [See Figure 4]. This also distinguishes the Carefree process from conventional coal cleaning.

The principal steps in the Carefree process are listed below and depicted in the following diagram:




- Recover a low specific gravity (1.30), coarse (plus ½mm) clean coal product.

- Reject a high specific gravity (1.75), coarse refuse.

- Crush the resulting middling product (specific gravity 1.30 by 1.75) to liberate pyrite, other ash-forming minerals and coal.

- Size and classify the resulting minus ½mm comminuted and "natural" material into three fractions: fines, ultra-fines and slimes.

- Clean the fines and ultra-fines in dense medium cyclone circuits. These circuits employ magnetite that is an order-of-magnitude smaller than conventional magnetite, and cyclones of unique design. Recover the magnetite in circuits designed for the size of the coal and refuse particles.

- Dewater all the clean coal fractions: coarse, fine and ultra-fine. Some thermal drying may be required depending upon the coal.

Self-Scrubbing Coal is a compliance product prepared from non-compliance coals that have moderate organic sulfur and pyrite that liberates easily. The sulfur is removed in two steps, one occurs in the coal preparation plant, the other in the boiler. Self-Scrubbing Coal is first aggressively beneficiated, as described above. Both pyrite and ash are reduced as much as possible while at the same time maintaining a high Btu recovery. The sorbent: dolomite, limestone or dolomitic limestone, is then agglomerated (pelletized) with the ultra-fine fraction of the clean coal. The purpose of the sorbent is to capture the sulfur dioxide produced when the organic sulfur and residual pyrite are oxidized during combustion. The final clean coal product from the above process is Self-Scrubbing Coal. It is comprised of clean coarse coal, clean fines and pellets containing clean ultra-fine coal and sorbents.

As an example, Custom Coals evaluated a Lower Freeport coal from eastern Ohio. The raw coal has 6.4 lbs $SO_2$/MMBtu. The organic sulfur content is moderate and the pyrite liberates easily. A 1.2 pound compliance Self-Scrubbing Coal can be made from this feedstock.

Through aggressive beneficiation the 6.4 lbs $SO_2$/MMBtu in the raw coal can be reduced to 2.1 pounds. Cleaning to 2.1 pounds removes 67 percent of the total sulfur in the raw coal. To produce Self-Scrubbing Coal, limestone is pelletized with the ultra-fines and the pellets are combined with the clean coarse and clean fine coal. The amount of limestone added is 16.8 percent based on the total weight of Self-Scrubbing Coal. The calcium-to-sulfur stoichiometry in the resulting product is 2.4. An estimated 43 percent of the sulfur in this Self-Scrubbing Coal will be captured in the boiler through sulfation of the sorbent. Predictions of sulfur capture in the boiler are based upon data from the literature from full-scale plant and test-boiler evaluations of $SO_2$ capture by sorbents entering the boiler with the fuel and pilot-scale testing by Custom Coals. Sulfur-capture values, as a function of sorbent stoichiometry, will be confirmed by full-scale boiler test burns as part of the CC IV project. The final emission limit of 1.2 pounds of sulfur dioxide comprises a total sulfur reduction of 81 percent.

Analyses of the products from raw coal to Self-Scrubbing Coal are given in the following table:

| Product | Ash, Percent | Lbs $SO_2$/MMBtu | Incremental $SO_2$ Reduction Percent | Total $SO_2$ Reduction Percent |
|---|---|---|---|---|
| *Raw Coal* | 12.8 | 6.35 | N/A | N/A |
| *Cleaned Coal* | 3.7 | 2.08 | 67.2 | 67.2 |
| *Self-Scrubbing Coal* | 13.3 | 1.18 | 43.3 | 81.4 |

Several improvements result from using Self-Scrubbing Coal compared to earlier combustion trials by others in which the sorbent and coal were injected together through the burner.

- Less sintering occurs with low-$NO_X$ burners which are expected to be installed by most utilities to comply with the $NO_X$ reduction requirements of the 1990 Clean Air Act Amendments. Sintering causes a loss of sorbent reactivity due to a reduction in the surface area of the sorbent. Greater sintering occurs at higher temperatures and less at lower temperatures. Sintering is minimized by low-$NO_x$ burners that provide an improved time/temperature profile for $SO_2$ capture.
- The quantity of ash is not excessive. Aggressively beneficiating the coal before introduction of the sorbent keeps ash levels near or below pre-established levels.
- Higher removals of sulfur dioxide are possible due to greater calcium-to-sulfur stoichiometry. The aggressive beneficiation reduces sulfur substantially. For a given quantity of sorbent, lower sulfur levels mean greater calcium-to-sulfur ratios. And, proportionately greater capture of sulfur dioxide occurs with higher calcium-to-sulfur ratios.

- The percent removal of sulfur dioxide is good. A capture of 43 percent by sorbent addition to the coal, that attained in the above example, would be considered poor if viewed as a stand-alone technology. When sorbent addition is integrated with CCI's aggressive coal cleaning process, total sulfur reduction is a very respectable 81 percent. This is sufficient to bring many coals into long-term compliance.

Self-Scrubbing Coal attains year-2000 compliance with coals of moderate organic sulfur and pyrite that liberates easily. No additions to or modifications of the boiler are required with Self-Scrubbing Coal. It is received, stored, reclaimed, pulverized and burned the same as conventionally prepared coal.

**PLANT DESIGN**

The preparation plant will be located in Stoystown, Pennsylvania at the site of the existing idled Quemahoning Preparation Plant built in the late 1970's by Gulf & Western. A substantial percentage of the handling facility infrastructure will be refurbished and reused. The preparation plant building itself will be demolished and replaced. The site will include the following sections:

- Raw Coal Handling - The site will be equipped to receive coal either by truck or overland conveyor belt. The raw coal handling system consists of truck dumps, raw coal conveyors, 4000 tons of raw coal silo storage capacity and a scalping screen and crusher station. The site was designed to facilitate a two-product (steam or metallurgical coal) feed.
- Coarse Coal Circuit - A conventional heavy media cyclone circuit is used to clean the coarse material defined as 1½" by ½mm. The circuit is operated to remove very clean coal using a 1.30 specific gravity float and refuse material using a 1.75 specific gravity sink. The middlings material (1.30 sink by 1.75 float) is crushed and proceeds to the next cleaning circuit.
- Fine Coal Circuit - In advance of the fine and ultra-fine cleaning circuits, a classifying cyclone circuit is used to remove the -500 mesh material consisting primarily of clay slimes. The fine coal cleaning circuit utilizes ultra-fine magnetite

and redesigned cyclones to achieve effective cleaning in the ½mm by 150 mesh size fraction.

- Ultra-Fine Circuit - The ultra-fine magnetite and redesigned cyclones are also used to clean the 150-500 mesh material. The magnetite recovery system uses barium ferrite and rare earth magnetic separators to recover the ultra-fine magnetite.
- Coal Drying/ Pelletizing - Sorbent and binders are mixed with ultra-fine clean coal which is then pelletized and thermally dried.
- Clean Coal Handling - Clean coal proceeds on a collecting conveyor through an automatic sampling system and on to two clean coal silos (3,500 tons each). From the silos either trucks or unit trains can be loaded. The plant is on the B&O Railroad.

## PROJECT SCHEDULE

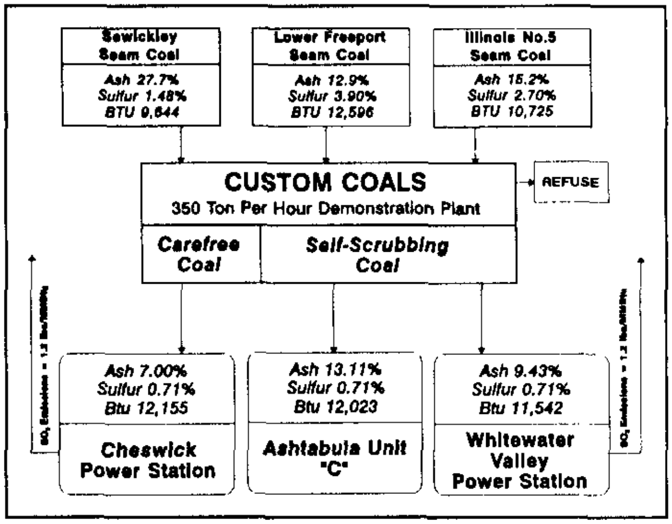
The project has been divided into five phases as described below and will continue through September 30, 1995. The project is currently completing the Preaward Phase and preparing to begin the Project Definition Phase.

| Phase | Description | Length |
|---|---|---|
| *I* | Preaward | 12 Months |
| *II* | Project Definition | 6 Months |
| *III* | Design | 6 Months |
| *IV* | Construction | 16 Months* |
| *V* | Operation | 16 Months |

* 6-month overlap with the design phase

## TEST BURNS

The test burn phase of the project is comprised of test planning, coal preparation and combustion and data analysis and reporting. Test planning at each host site will include a detailed review of power plant performance records, a walk-down of each test unit to select appropriate access ports for test measurements, a meeting to discuss host utility requirements and test objectives and the preparation of a detailed test plan that documents required plant modifications to accommodate the test program, a test matrix of proposed operating conditions and measurements to be made during the test and a schedule for each of the tests to be conducted.




During each of the test burns, unit thermal performance will be determined for the entire combustion system - from the pulverizers to the precipitators. Specific coal samples, flue gas samples, ash and slag samples, pressures, temperatures and instrument data will be collected to determine energy consumption, efficiency and process performance for the combustion system. Comparison to design specifications and past performance will be the basis for measuring the costs and benefits of the test coals over a 30-day test period at steady-state baseload.

During the thermal performance tests, supplemental monitoring will be performed to measure environmental performance. On-line monitors, flue gas sampling and solids sampling will provide accurate measurements of:

- $SO_2$ emissions
- $NO_X$ emissions
- $CO_2$ emissions
- Air toxics emissions
- Solid waste quantities and characteristics

The results of the tests for each coal will be documented in detailed reports. These three reports will describe coal handling and sampling procedures, as-received coal quality of the test coals, power plant test procedures and data collected, results of data analyses and an assessment of the costs and benefits in terms of thermal performance and emissions for the test coals.

Custom Coals will facilitate technology transfer to the host utilities and to the utility industry as a whole. Technical briefings will be provided for each of the host utilities following completion of the respective field test efforts. The results of the field tests will also be presented at an appropriate national conference.

The objective of this technology is to generate coals that will meet the Clean Air Act requirements of 1.2 lbs $SO_2$/MMBtu. The major competing technologies are Flue Gas Desulfurization (FGD), coal cleaning with FGD and advanced coal cleaning.

Conventional FGD technology (wet scrubbers) uses lime or limestone to capture sulfur pollutants in the flue gas before it exits the stack. This technology tends to be plagued by corrosion and plugging; it also produces a wet waste product (sludge), which might have high disposal costs. Advanced FGD technologies encompass two approaches: (1) using existing flue gas ductwork to inject a sorbent and (2) inserting one or more separate vessels into the downstream ductwork where pollutant adsorbents are added. Adding a separate vessel allows greater residence time for sorbent reaction and improves removal efficiency, however, the vessel is costlier to install than duct injection and requires more space. Advanced FGD systems are being demonstrated but the final results and total costs still need to be determined.

Conventional coal cleaning techniques can be divided into density (gravimetric) or surface properties (psyiochemical processes). The major process used for fine coal separation (less than 150 microns) is froth flotation. This process is used primarily for ash separation but it is not particularly effective for pyrite removal because of similarities in surface properties between coal and pyrite.

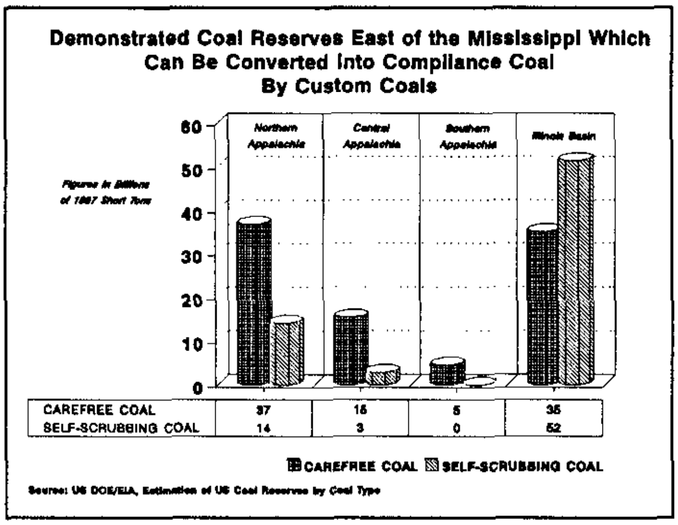
Advanced coal cleaning techniques can be separated into physical or chemical cleaning processes. Physical coal cleaning processes are only able to remove inorganic sulfur which is associated with the mineral matter as opposed to the organic sulfur which is bound to the coal structure and is much more difficult to remove. The chemical removing processes can remove both inorganic and organic sulfur and may remove as much as 90 to 95% of the pyritic sulfur and 40 to 85% of the inorganic sulfur. However, none of these processes have been demonstrated at near commercial scale and it is not expected that full scale demonstrations will occur within the next five to ten years. There are numerous handling problems with the corrosive reagents and toxic agents that have to be resolved. In summary, the cleaning of coal by chemical techniques is not likely to find near-term (five to ten years) application in the industry.

A number of advanced physical coal cleaning processes are currently under development by industry and DOE. Many of these processes under development involve difficult to handle chemical media and more complex chemical processing. The advanced froth flotation systems will challenge the CCI process in ash reduction, however, it will have difficulty matching the CCI pyritic sulfur removal performance, especially for low rank or oxidized coals. The DOE MicroMag process is similar to CCI's process except that the CCI's process employs a patented modified cyclone which accelerates the separation of extremely fine coal from the associated refuse. As a result, industry acceptance of these advanced physical coal cleaning processes is not expected for at least five years.

## COMMERCIALIZATION

The current United States coal market is one billion tons per year. Of this, approximately 80% is sold to the electric utility industry. About 300 million tons of the utility industry consumption represents Western low-sulfur coal or unwashed strip mined coal. Of the remaining 500 million tons, Custom Coals has determined that at least half is burned in locations where strong economic or operating considerations could favor Self-Scrubbing Coal over alternate compliance solutions. Custom Coals seeks to achieve 10-20% share of this fraction of the market.

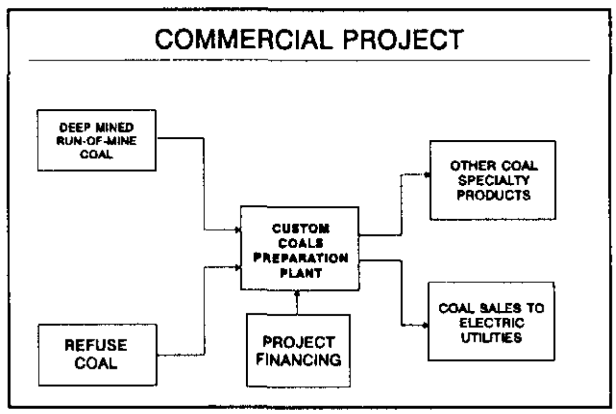
An analysis was performed of boilers affected by Phase I and Phase II of the Acid Rain Provisions. The best candidates for Carefree Coal and Self-Scrubbing Coal are thought to be those boilers over 20 years old and plants where scrubber retrofits are more costly. The analysis was combined with an assessment of available coals which can be brought into compliance with Custom Coals' technology as indicated in the following graph. From these combined analyses, the market size potential discussed above was developed.




Custom Coals' strategic plan is to acquire low cost non-compliance coal, bring it into compliance through the application of the technology and sell it near the avoided cost of other compliance alternatives. Custom Coals will construct a series of preparation plants to produce compliance coal products. The current forecast calls for 10 plants to be constructed in the United States by the year 2000.

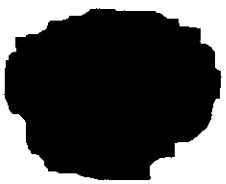
A substantial market for Custom Coals' products is also developing in Eastern Europe. The Polish government has requested that a feasibility study be performed to assess the potential for constructing 14 coal cleaning plants with a total capacity of 50 million tons of coal per year. Funding is currently being sought to execute the feasibility work and begin serious negotiations for the first three plants. Similar opportunities exist elsewhere in Eastern Europe and in the former Soviet Union.

The United States market is being approached by developing conceptual project opportunities using Custom Coals knowledge of the electric utility industry and the coal markets. Potential clean coal purchasers from the project are then contacted to determine if a sufficient level of interest exists to proceed with the project. Given a positive response, Custom Coals then identifies raw coal supplies and a preparation plant site. Coal industry consultants and coal preparation plant engineers are used to assist Custom Coals in developing the project concept into a series of contracts that can be project financed. In May 1992 Custom Coals executed an agreement with Chase Manhattan Bank, establishing a vehicle through which up to $500 million of project financing capacity will be made available to construct at least 10 coal preparation plants. The general project model is shown below.

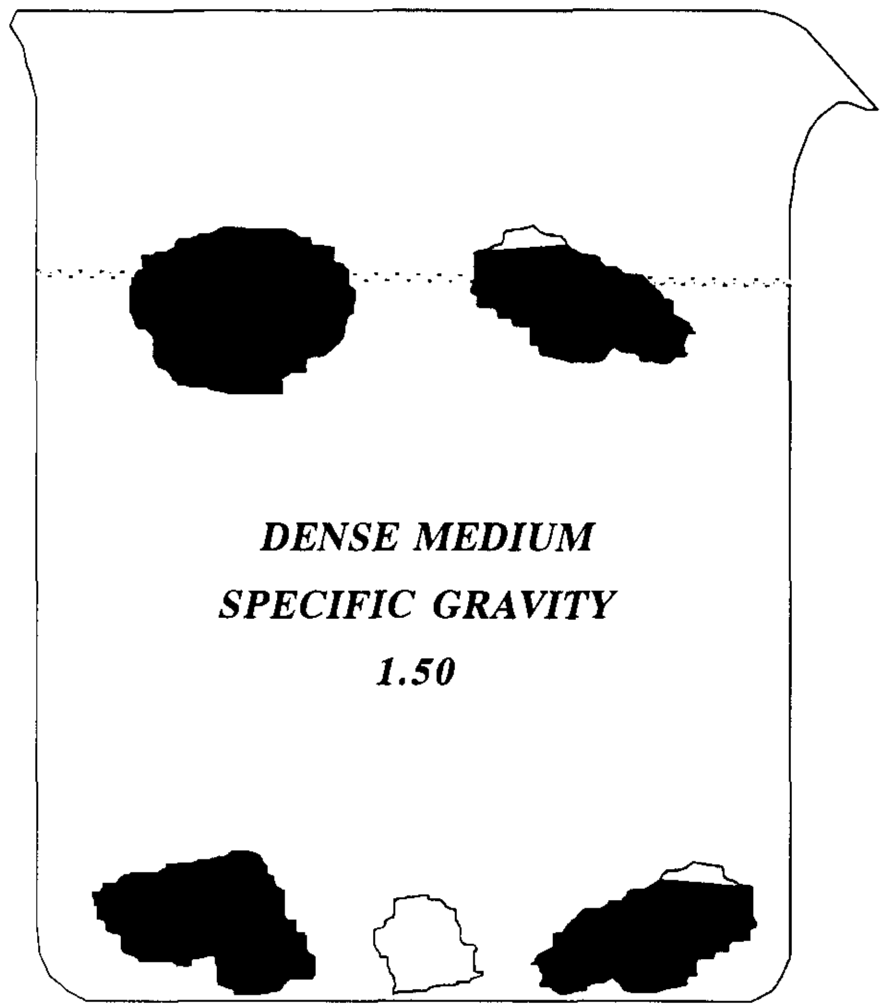



Sales to Eastern Europe are being approached through the respective government entities as the coal supply and electric generating facilities are generally government owned. Again, coal industry consultants and coal preparation plant engineers are used to assess project opportunities and develop required contracts. Financing will be accomplished through bank loans guaranteed by international agencies and equity as required. Payment will be in the form of clean coal which will be sold in the Western Europe market.

# TYPES OF PARTICLES IN RUN-OF-MINE (ROM) COAL

| SYMBOL | MATERIAL | SPECIFIC GRAVITY | PARTICLE TYPE |
|---|---|---|---|
|  | COAL | 1.30 | FREE |
|  | REFUSE | 2.60 | FREE |
|  | PYRITE | 5.00 | FREE |
|  | MIDDLING | 1.55 | LOCKED |
|  | MIDDLING | 1.45 | LOCKED |

# SEPARATION OF ROM COAL PARTICLES BY CONVENTIONAL DENSE MEDIUM PROCESS



**THRI**

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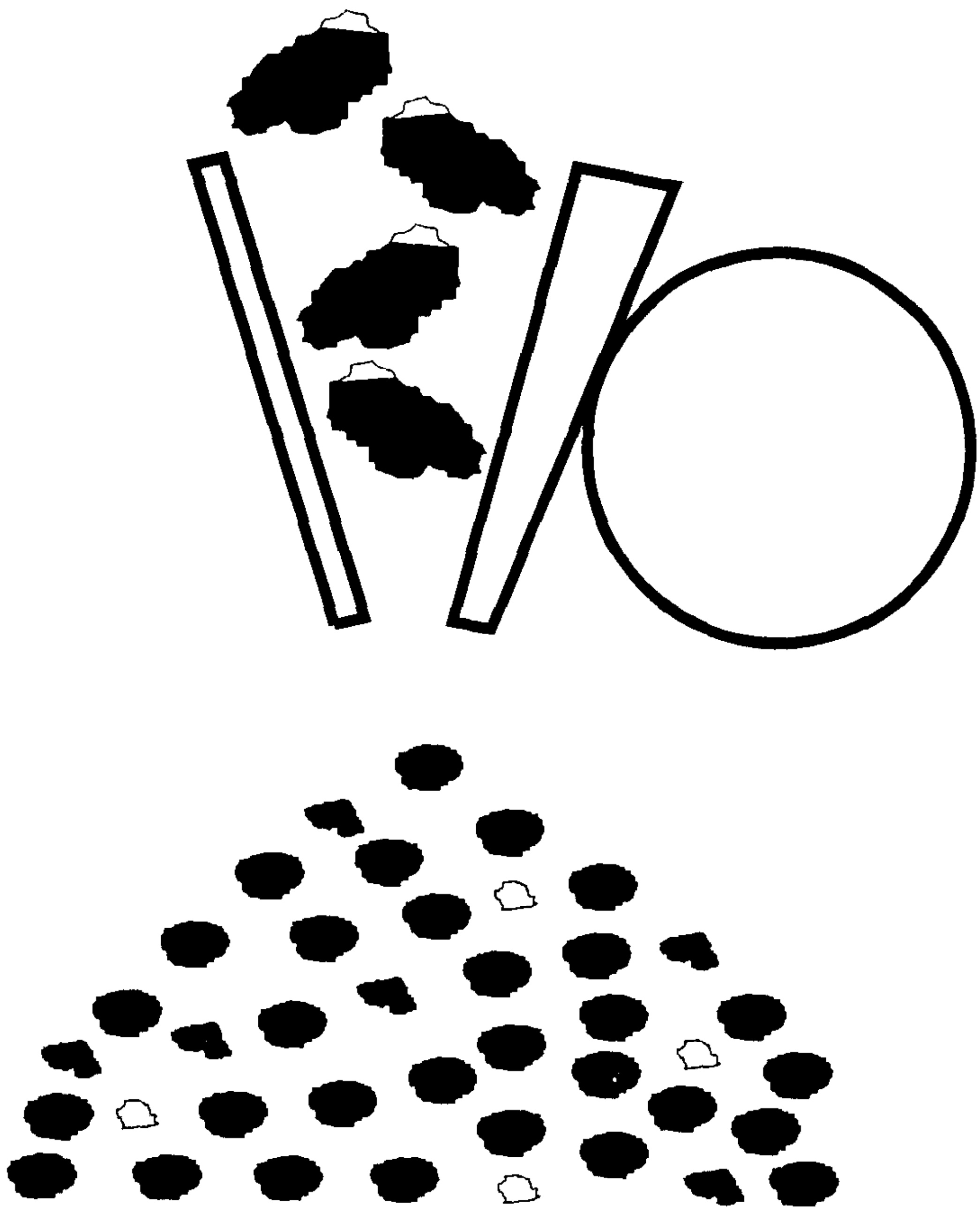
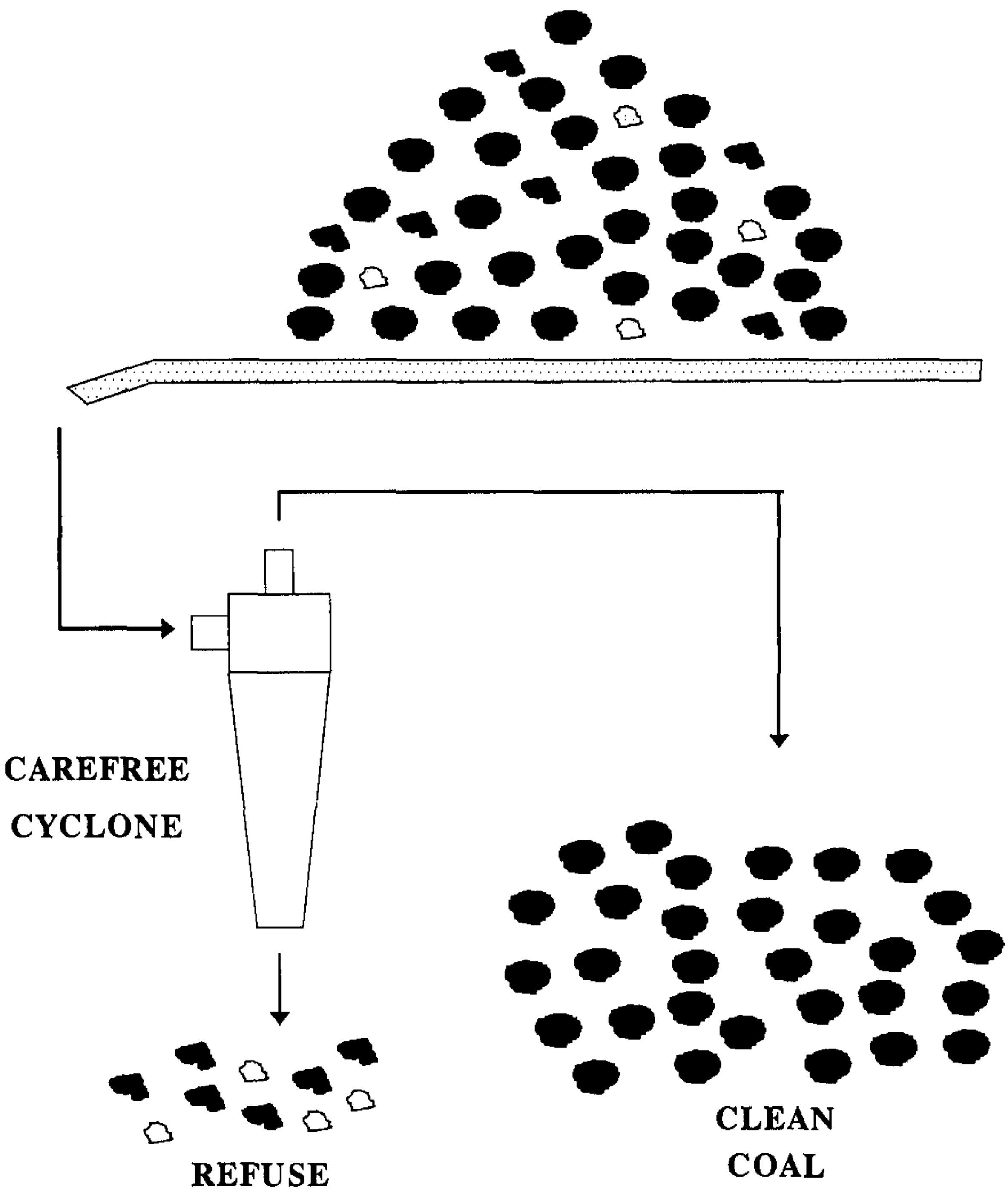
# LIBERATING PYRITE AND COAL BY CRUSHING AND GRINDING THE MIDDLINGS



# BENEFICIATING CRUSHED MIDDLINGS TO REJECT PYRITE AND RECOVER ADDITIONAL CLEAN COAL



# SESSION 7:
# $NO_x$ Control Systems

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**Full Scale Demonstration of Low $NO_x$ Cell™ Burners at Dayton Power & Light's J.M. Stuart Station Unit No. 4**, Roger J. Kleisley, Contract Manager, The Babcock & Wilcox Company, David A. Moore, Engineering Supervisor, Dayton Power & Light. Co-authors: C.E. Latham and T.A. Laursen, The Babcock & Wilcox Company, and C.P. Bellanca and H.V. Duong, Dayton Power & Light

**Demonstration of Coal Reburning for Cyclone Boiler $NO_x$ Control — A DOE Clean Coal II Project**, Anthony S. Yagiela, Cyclone Reburn Project Manager, The Babcock & Wilcox Company. Co-authors: G.J. Maringo, Combustion Systems Development Engineer, The Babcock & Wilcox Company, R.J. Newell, Supervisor, Plant Performance, Wisconsin Power & Light, and H. Farzan, Senior Research Engineer, The Babcock & Wilcox Company

**Gas Reburning for Combined $NO_x$ and $So_2$ Emissions Control on Utility Boilers,** Leonard C. Angello, Director, Utility Systems, Energy and Environmental Research Corporation. Co-authors: D. A. Engelhardt, B.A. Folsom, J. C. Opatrny, T.M. Sommer, Energy and Environmental Research Corporation, and H.J. Ritz, U.S. DOE Pittsburgh Energy Technology Center

**Integrating Gas Reburning with Low $NO_x$ Burners,** Todd M. Sommer, Vice President, Energy and Environmental Research Corporation. Co-authors: C.C. Hong, H. M. Moser, Energy and Environmental Research Corporation, H. J. Ritz, U.S. DOE Pittsburgh Energy Technology Center

**Micronized Coal Reburning for $NO_x$ Control on a 175 MWe Unit**, Dale T. Bradshaw, Manager, Resource Development Department, Tennessee Valley Authority. Co-authors: Thomas F. Butler, Tennessee Valley Authority, William K. Ogilvie, MicroFuel Corporation, Ted Rosiak, Jr., Duke/Fluor Daniel, and Robert E. Sommerlad, Research-Cottrell Companies

**Integrated Dry $NO_x/SO_2$ Emissions Control System Update**, Terry Hunt, Professional Engineer, Public Service Company of Colorado. Co-author: John B. Doyle, The Babcock & Wilcox Company

# FULL SCALE DEMONSTRATION OF LOW $NO_x$ CELL™ BURNERS AT DAYTON POWER & LIGHT'S J. M. STUART STATION UNIT NO. 4

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## ABSTRACT

*Currently, utility boilers equipped with cell burners comprise 13% of pre-New Source Performance Standards (NSPS) coal fired generating capacity. The cell burner rapidly mixes the pulverized coal and combustion air resulting in rapid combustion and high $NO_x$ generation. A U.S. Department of Energy (DOE) Clean Coal Technology Demonstration project is underway at Dayton Power & Light's J.M. Stuart Station to demonstrate the Low-$NO_x$ Cell™ burner (LNCB™) on a 605-MWe utility boiler originally equipped with cell burners. The LNCB™ is designed to reduce $NO_x$ emissions by delaying the mixing of the coal and the combustion air without boiler pressure part modifications.*

## INTRODUCTION AND BACKGROUND

The "Full-Scale Demonstration of Low-$NO_x$ Cell™ Burner Retrofit" (Project DE-FC22-P0P90545) is one of the U.S. Department of Energy (DOE) Clean-Coal Technology (CCT-III) Demonstration Program projects. The objective of the LNCB™ demonstration is to evaluate the applicability of this technology for reducing $NO_x$ emissions in full-scale, cell-burner-equipped boilers. The program objectives are:

1. Achieve at least a 50% reduction in $NO_x$ emissions
2. Reduce $NO_x$ with no degradation to boiler performance or life
3. Demonstrate a technically and economically feasible retrofit technology

The project organization is comprised of the following groups:

- DOE - funding co-sponsor
- Babcock & Wilcox (B&W) - prime contractor, project manager, and funding co-sponsor
- Dayton Power & Light (DP&L) - host site utility, operations and construction management, and funding co-sponsor
- Electric Power Research Institute (EPRI) - testing consultant and funding co-sponsor
- State of Ohio Coal Development Office (OCDO) - funding co-sponsor
- Acurex Corporation - testing subcontractor
- Utility funding co-sponsors:
  - Allegheny Power System
  - Centerior Energy
  - Duke Power Company
  - New England Power Company
  - Tennessee Valley Authority

DP&L agreed to be the host utility for the full-scale demonstration of the LNCB™, offering the use of J.M. Stuart Station Unit No. 4 as the host site. Unit No. 4 is a 605-MWe universal pressure (UP) boiler originally equipped with 24, two-nozzle cell burners arranged in an opposed wall configuration.

To reduce $NO_x$ emissions, the LNCB™ has been designed to stage the mixing of the fuel and combustion air. A key design criterion for the LNCB™ was accomplishing delayed fuel-air mixing with no pressure part modifications. The traditional approach to cell burner modification was to increase the burner-to-burner spacing with pressure part modifications in addition to installing conventional, two-stage, low $NO_x$ burners. Pressure part modifications to rearrange the burners can be much more expensive. Material costs may more than double, and outage duration may double or triple.

## BURNER DEVELOPMENT

### Cell Burners

Economic considerations which dominated boiler design during the 1960s led to the development of the standard cell burner for highly efficient boiler designs. Each cell burner consists of two or three coal feed nozzles mounted in the lower furnace. A two-nozzle cell burner is shown in Figure 1. Cell burners were designed for rapid mixing of the fuel and

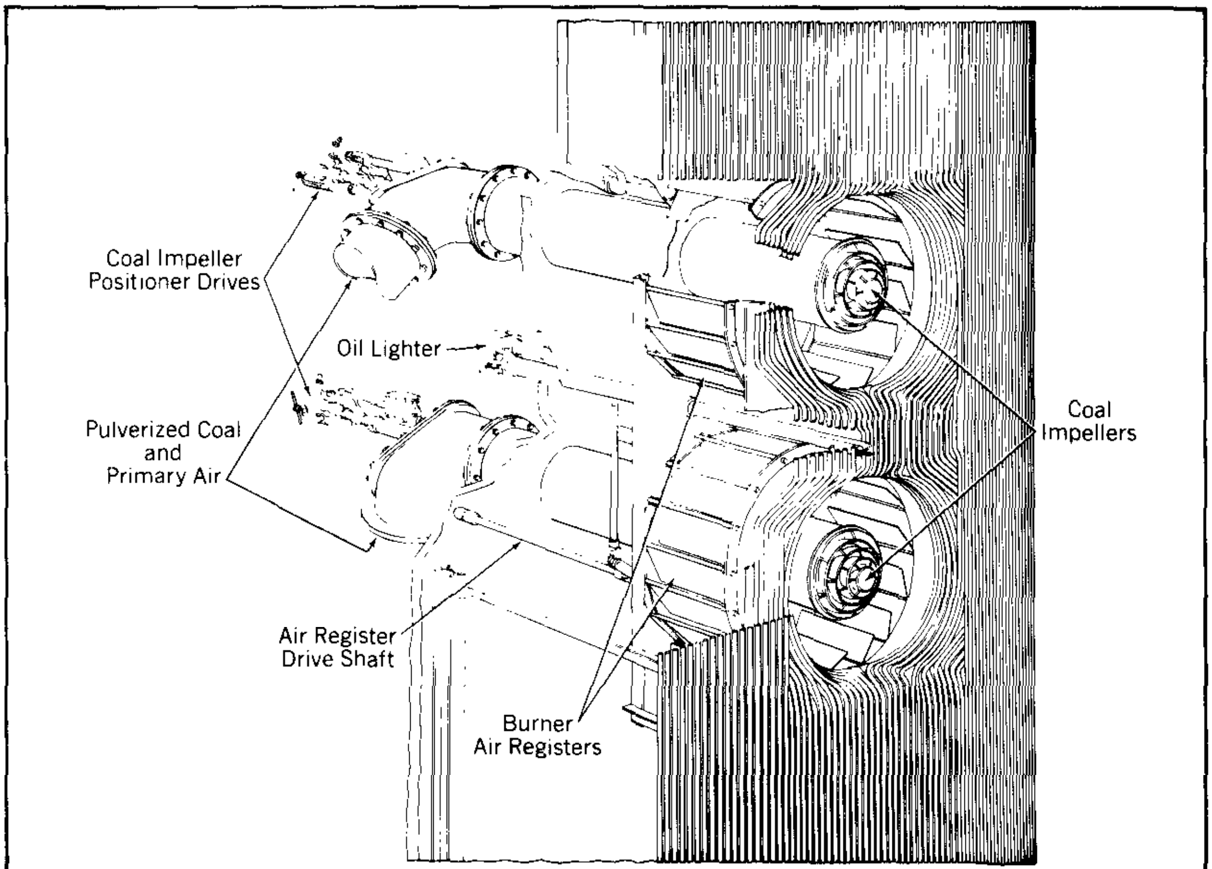


**Figure 1. Standard two-nozzle cell burner.**

oxidant. The tight burner spacing and rapid mixing minimize the flame size while maximizing the heat release rate and unit thermal efficiency. Consequently, the combustion efficiency is good, but the rapid heat release produces relatively large quantities of $NO_x$. Typically, $NO_x$ levels associated with cell burners will range from 1.0 to 1.8 lb $NO_x$ as $NO_2$ per million Btu input.

Low-$NO_x$ Cell™ Burner (LNCB™)

The two-nozzle LNCB™ shown in Figure 2 was developed by B&W in association with EPRI. The features of the LNCB™ were designed to restrict the formation of thermal and fuel $NO_x$. The original two coal nozzles in a cell burner are replaced with a single coal injection nozzle and a special secondary air injection port (or dedicated overfire air port).

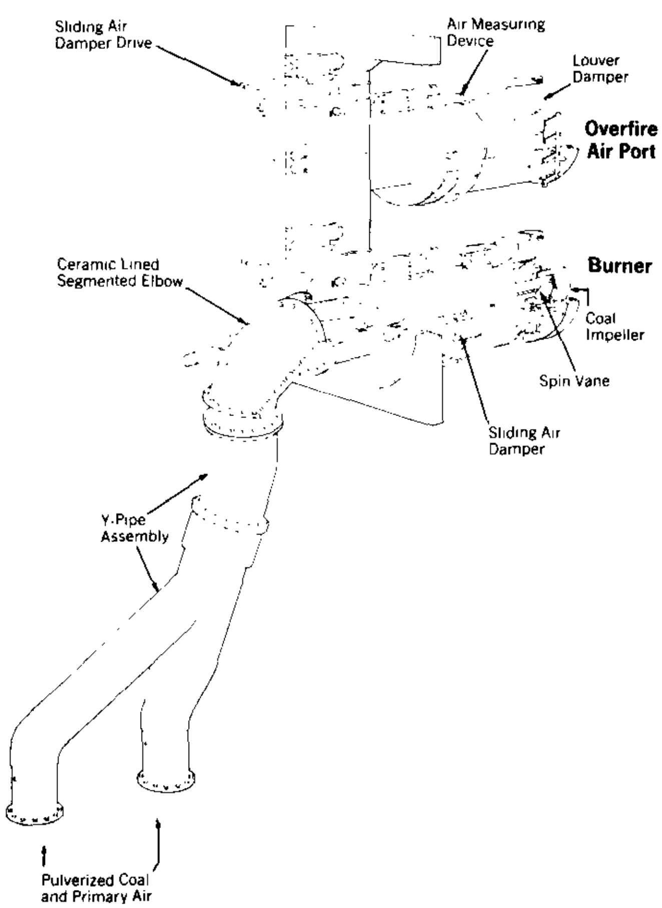


**Figure 2. Low $NO_x$ Cell™ burner.**

The flame shape is controlled using an impeller at the exit of the fuel nozzle and adjustable spin vanes in the secondary air zone. The air port louver dampers provide additional control over the mixing between the fuel and air streams. During operation, the lower fuel nozzle operates at a low stoichiometry, typically 0.6, with the balance of air entering through the upper port. The controlled mixing of the fuel and air delays the combustion, producing a longer flame that limits the production of $NO_x$.

The LNCB™ is designed to be directly installed into the existing cell burner furnace wall openings (no pressure part changes), without affecting requirements for coal storage, handling, or preparation. Only minor changes in coal piping near the burner will be needed to combine the two coal streams, leaving most of the pulverized coal transport piping intact. Secondary airflow is balanced burner-to-burner using sliding dampers in the air ports and burners. This arrangement typically increases the pressure loss on the secondary air flow system somewhat (1 to 2 in. wg). Since all units equipped with cell burners do not have the same design, a pre-installation engineering evaluation of the secondary air forced draft fans and combustion controls is recommended to determine if sufficient capacity exists to handle the flow resistance increase. In most cases, the existing controls will be sufficient.

Pilot Scale Testing

The novel design of the burner necessitated characterizing the burner at several scales showing feasibility at each scale to settle concerns about maintaining combustion performance. An integrated numerical and laboratory test program was designed to fully characterize the burner at several scales: 1.75-MW, 30-MW, and utility scale.[1] Several aspects of the LNCB™ performance were investigated, including $NO_x$ reduction, unburned carbon (UBC) loss, carbon monoxide (CO), corrosion, and impact to furnace exit gas temperature (FEGT). Results of the pilot scale studies showed that the LNCB™ burner arrangement was stable over the burner operating range and that greater than 50% $NO_x$ reduction was possible with acceptable impact to CO, UBC, and FEGT levels.

Three-dimensional numerical modeling was done before the pilot-scale testing to project burner performance and locate instrumentation. After the tests, predictions were compared to data, models were refined when required, and performance was scaled to the next level. In general, the pilot scale numerical modeling agreed well with the data.[2] Consequently, the models were used as a tool to assess the performance of the LNCB™ in a full scale utility boiler.

In 1985, one full scale, two-nozzle cell burner was replaced with an LNCB™ at DP&L's Stuart Station Unit No. 3 to test the mechanical reliability; Unit Nos. 3 and 4 have identical designs. Since the installation, all of the mechanical components of the burner have operated properly and stayed within material temperature limits.

Even though the feasibility of the burner was demonstrated at two pilot scale tests, and the mechanical reliability was established at full-scale, many other aspects of boiler operation may be effected by a low-$NO_x$ combustion system including combustion efficiency, heat transfer, and corrosion potential. The ongoing CCT-III Demonstration was designed to demonstrate the technical performance at full-scale, and thus the readiness of the technology for commercial operation.

## DEMONSTRATION BOILER

DP&L's J.M. Stuart Station Unit No. 4 is a B&W once-through, supercritical pressure boiler with a single reheat. A schematic of Unit No. 4 is shown in Figure 3. The 605-MWe boiler is now fired by 12, two-nozzle cell burners on each of the front and rear walls, arranged two rows high and six columns wide. Six MPS pulverizers supply pulverized coal to the 24 LNCB™ nozzles. The burner throat diameter is 38 in. Unit No. 4 burns Kentucky, Ohio, and West Virginia high-volatile bituminous coals. At full load, the boiler produces $4.4 \times 10^6$ $lb_m$/hr of main steam at 1005F and 3805 psia. The heat input per LNCB™ at full load is $219.4 \times 10^6$ Btu/hr.

## PROJECT SCHEDULE

The LNCB™ project covers a 38 month span which commenced in April 1990 and is

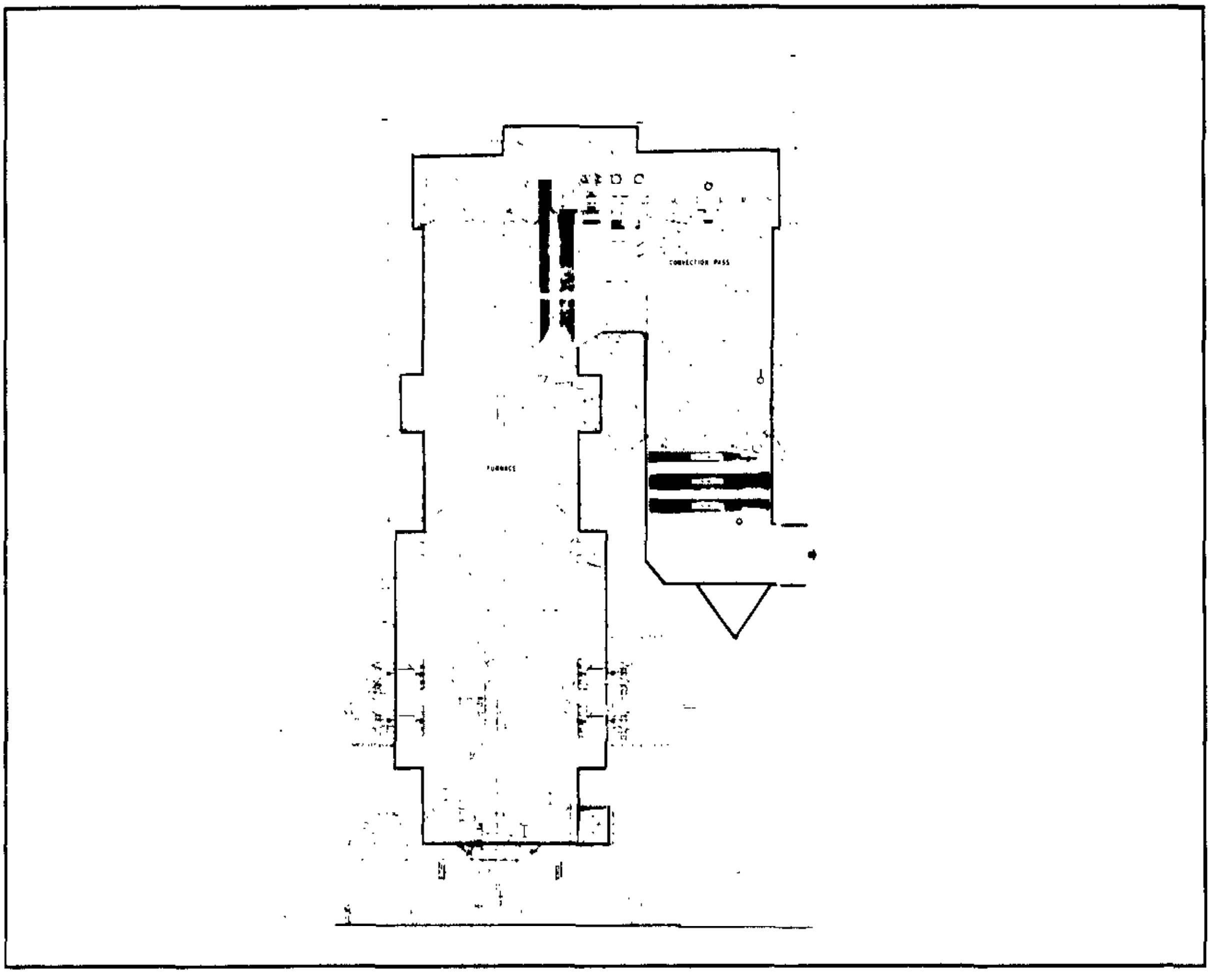

**Figure 3. DP&L J.M. Stuart station Unit No. 4.**

scheduled for completion in May 1993. Figure 4 shows key aspects of the project schedule and a breakdown of the various phases and tasks.

Key milestones accomplished to date are:

| | |
|---|---|
| Design Complete | 9/30/90 |
| Baseline Testing Complete | 11/8/90 |
| Completion of Installation | 11/2/91 |
| Optimization Testing Complete | 6/30/92 |

Remaining Milestones

| | |
|---|---|
| Long Term Testing Complete | 3/93 |
| Final Report and Project Complete | 5/93 |

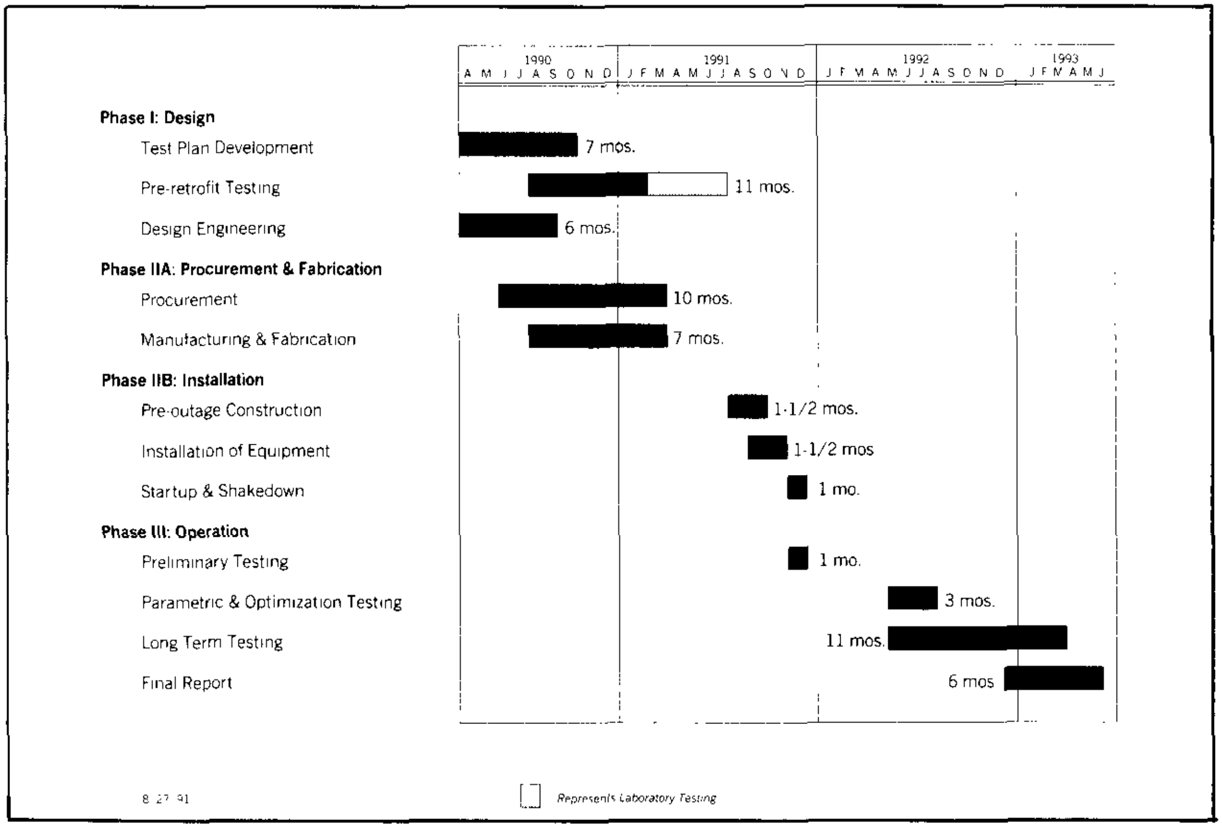


**Figure 4. Low-$NO_x$ Cell™ burner project schedule.**

## TEST PLAN

Test plans centered on the evaluation of boiler performance, boiler life, and environmental impact. Key boiler performance parameters that were measured included boiler output (steam temperatures); flue gas temperatures at the furnace, economizer and airheater exits; the slagging tendencies of the unit; and unburned combustible losses. Evaluation of hydrogen sulfide ($H_2S$) levels, ultrasonic testing of lower furnace tube wall thickness, and destructive examination of a corrosion test panel were the mechanisms used to gauge impact to boiler life.

Environmental impact was the major parameter to test. B&W and its testing subcontractor independently evaluated NO, $NO_x$, CO, $CO_2$, total hydrocarbons (THC), and particulate matter at various test points. Dust loading and precipitator collection efficiency testing were also important items in the evaluation.

Table 1. Preliminary test results.

## FULL SCALE DEMONSTRATION OF LOW NOx CELL™ BURNER
## BASELINE, INITIAL STARTUP, AND FINAL ARRANGEMENT PRELIMINARY TEST RESULTS

| | STANDARD CELL | LOW NOx CELL™ BURNER OPERATION | | | LNCB FINAL ARRANGEMENT |
|---|---|---|---|---|---|
| TEST REFERENCE | BASELINE TEST 1 | IMPELLER NORMAL POS. | IMPELLER RETRACTED | FURNACE MINIMUM CO | ALT INVERTED TEST 29 |
| DATE | BASELINE 10/22/90 | INIT. STARTUP 11/25/91 | INIT. STARTUP 11/27/91 | INIT. STARTUP 12/04/91 | PARAMETRIC 6/03/92 |
| NOx LBS/MMBtu | 1.172 | 0.762 | 0.645 | 0.820 | 0.526 |
| NOx PPM @ 3%O2 | 858 | 558 | 472 | 600 | 385 |
| NOx REDUCTION | N/A | 35% | 45% | 30% | 55% |
| STOICHIOMETRY | N/A | 0.59 – 0.66 | 0.54 – 0.68 | 0.8 | 0.60 – 0.70 |
| WINDBOX-FURNACE PRESSURE DROP | 1.93 in. Wg. | 2.24 in. Wg. | 2.62 in. Wg. | 3.69 in. Wg. | 4.42 in. Wg. |
| CO IN LOWER FURNACE* | 0 – 0.1% # | 10 – 12% | 8 – 10% | 3.5 – 4.5% | 0 % |
| H2S IN LOWER FURNACE** | | | | | |
| EAST (LEFT HAND) SIDEWALL | 0 PPM | NO SAMPLE | 400 PPM | 0 PPM | 0 PPM |
| WEST (RIGHT HAND) SIDEWALL | 100 PPM | NO SAMPLE | 1000 PPM | 400 PPM | 0 PPM |
| O2 AT ECONOMIZER OUTLET | | | | | |
| EAST (LEFT HAND) SIDE | 3.4% | 3.6% | 3.2% | 3.5% | 3.58% AVG. |
| WEST (RIGHT HAND) SIDE | 3.7% | 3.9% | 3.7% | 4.7% | |
| CO AT ECONOMIZER OUTLET | 29 – 30 PPM | 27 – 32 PPM | 21 – 29 PPM | 20 – 26 PPM | 41 PPM |
| LOI – BOTTOM ASH | 1.0 – 7.6% | 5.01% | NOTE 2 | NO SAMPLE | 1.11% |
| LOI – 1ST FIELD OF PRECIPITATOR | | | | | |
| EAST (LEFT HAND) SIDE | NOTE 1 | 1.22% | NOTE 2 | NO SAMPLE | COMPOSITE L&R |
| WEST (RIGHT HAND) SIDE | NOTE 1 | 1.64% | NOTE 2 | NO SAMPLE | 2.92% |

* TAKEN THROUGH AN OBSERVATION DOOR OPENING AT ELEVATION 564'-10".

** TAKEN THROUGH AN OBSERVATION DOOR OPENING AT ELEVATION 556'-2".

# DATA TAKEN ON STUART UNIT # 2 ON 11/19/91.

NOTE 1: BASELINE TEST REPORT DOES NOT DIFFERENTIATE BETWEEN LEFT AND RIGHT. BASELINE TEST RESULTS RANGED FROM 1.14% TO 2.53% LOI.

NOTE 2: ASH SAMPLES WERE TAKEN ON 12/02/91 UNDER THE SAME BURNER SETTINGS AS 11/27/91. LOI RESULTS FOR 12/02/91 WERE BOTTOM = 3.02%, LEFT = 2.41%, AND RIGHT = 1.94%.

## TEST RESULTS

Baseline testing of Stuart Station Unit 4 was completed in November 1990. The results showed the unit was performing well, with efficiencies averaging 89.59% at full load with all mills in service. At these conditions, $NO_x$ emissions were 1.17 lb/$10^6$ Btu, which is typical of such units. Combustion efficiency was very good with carbon in the flyash averaging 1.8% Loss on Ignition (LOI). CO emissions averaged near 30 ppm (at 3% $O_2$).

Following installation of the burners in the fall of 1991, LNCB™ preliminary post-retrofit testing was halted on December 6, 1991. Results of the preliminary testing (Table 1) showed a need for two LNCB™ design changes prior to resumption of testing. The first change involved the replacement of 24 burner impellers. The best $NO_x$ reduction with the original configuration was 35%. Pilot scale testing, as well as simulated testing at the DP&L Stuart Station boiler, indicated that a shallower angled impeller would allow the project goal of 50% $NO_x$ reduction to be achieved.

The second design change was necessary due to higher than expected flue gas CO and $H_2S$ concentrations inside the lower furnace/ash hopper zone, below the lowest burner row. DP&L Stuart Unit No. 4 is a pressurized furnace; high CO concentrations would pose a personnel hazard should a casing leak develop. High $H_2S$ concentrations in the entire lower furnace would lead to accelerated boiler tube wall wastage. DP&L found both of these to be unacceptable operating conditions. The sub-stoichiometric operation of the lowest burner row (Figure 5) was the direct cause of the situation. B&W used its three-dimensional numerical analysis computer programs to simulate furnace conditions with the original LNCB™ configuration. The program substantiated initial conditions, and also allowed simulation of alternative burner/$NO_x$ port arrangements that could mitigate the problem. The best computer generated analysis identified for maximum mitigation of CO and $H_2S$ levels was to invert the air port and burner of every other LNCB™ on the lowest level of burners (Figure 6).

These changes were implemented in May 1992. When parametric testing was resumed, it showed that the modifications produce the desired performance conditions. The LNCBs™

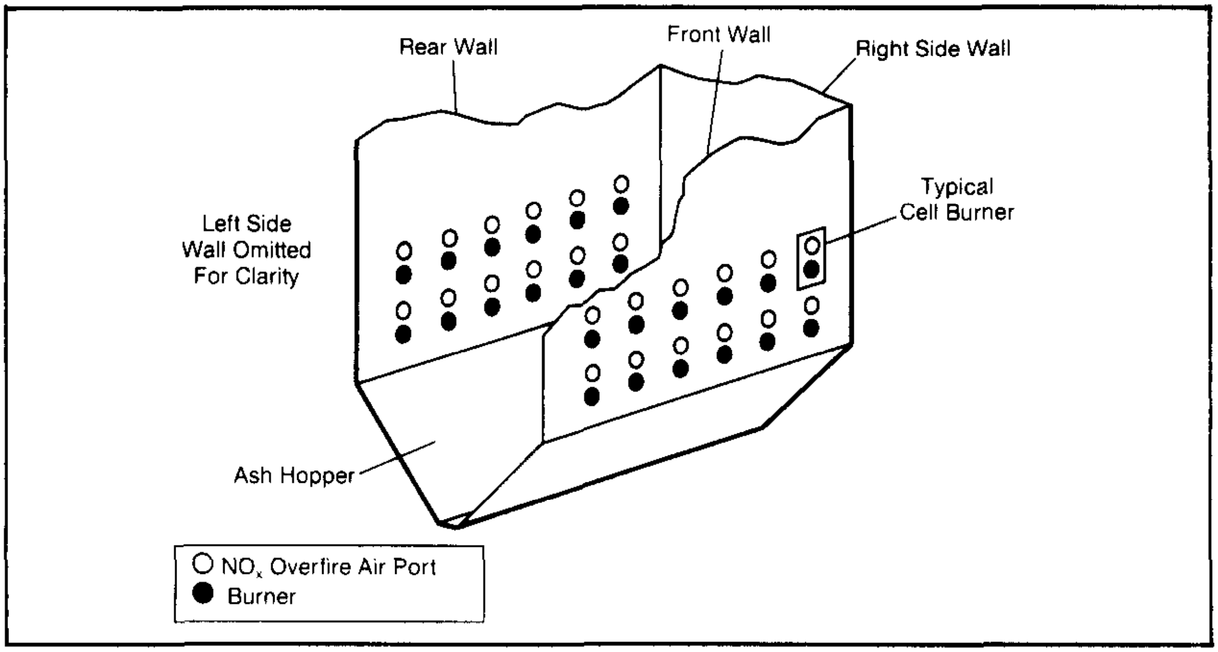


**Figure 5. LNCB™ original arrangement.**

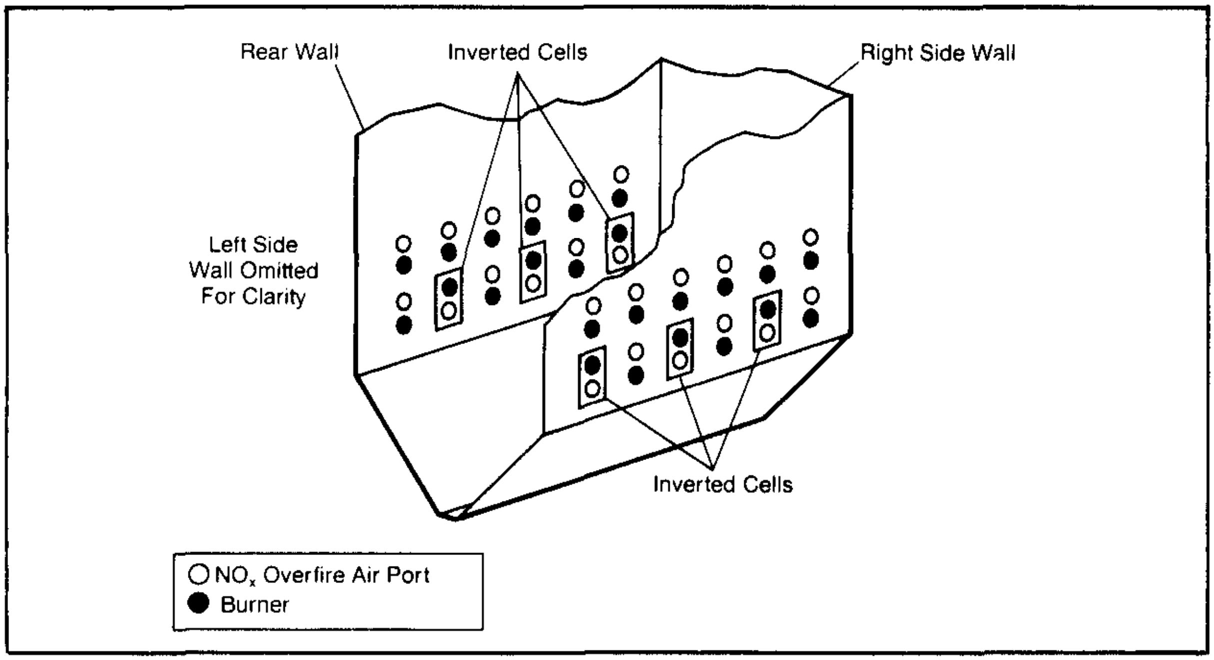


**Figure 6. Partially inverted LNCB™ arrangement.**

are achieving 55% $NO_x$ reduction (0.526 lbs/$10^6$ Btu) and CO in the lower furnace is less than baseline cell burner levels. Carbon in the flyash is averaging 3 to 4% LOI and CO emissions are 40 to 50 ppm. Complete optimized test results are not yet available as optimized testing concluded June 30, 1992. Long-term testing will be ongoing until the spring of 1993.

## CONCLUSION

By exceeding the 50% $NO_x$ reduction goals, the LNCB™ design has already achieved most of its clean coal program objectives. Corrosion potential is still being investigated and complete results will not be available until after DP&L Unit 4's spring 1993 outage.

Currently, there are 34 operating units with cell burners. They generate 23,639 MW and represent 13% of pre-NSPS coal-fired generating capacity. Of these 34 units, 29 are opposed-wall-fired with two rows of two-nozzle cells and have an average size of 766-MWe. Five units are opposed-wall-fired with two rows of three-nozzle cells and have an average size of 285-MWe. Applicability to the three-nozzle cell burner design is still under investigation.

The low cost and short outage time for retrofit make the design financially attractive. In a typical retrofit installation, the capital cost will include the LNCB™ hardware, coal pipe modifications, hangers, support steel, sliding air damper drives, and associated electricals, with a capital cost of about $8 to 12 per KW in 1990 dollars, based upon the DOE 500-MWe reference unit for material and erection. The outage time can be as short as five weeks because the LNCB™ is a plug-in design.

## REFERENCES

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# DEMONSTRATION OF COAL REBURNING FOR CYCLONE BOILER $NO_x$ CONTROL - A DOE CLEAN COAL II PROJECT

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## INTRODUCTION

Babcock & Wilcox has developed, through a U.S. Department of Energy Clean Coal II Project, "Demonstration of Coal Reburning for Cyclone Boiler $NO_x$ Control," a technology which provides Cyclone- operating utilities with an alternative for $NO_x$ compliance strategies. The host site for this demonstration is Wisconsin Power & Light Company's (WP&L) Nelson Dewey Unit No. 2 in Cassville, Wisconsin.

The coal reburning system includes the addition of reburn burners, overfire air (OFA) ports, an MPS pulverizer, and a control system modification, and is designed to retrofit Cyclone-fired boilers. Both pilot and full-scale testing demonstrate that this technology is capable of reducing $NO_x$ by 50 to 60% from baseline levels.

The objective of the Cyclone coal reburning demonstration is to evaluate the applicability of the coal reburning technology for reducing $NO_x$ emissions in full-scale, Cyclone-equipped boilers. The performance goals are:

(1) Provide a technically and economically feasible low-$NO_x$ alternative for Cyclone boilers to achieve a greater than 50% $NO_x$ reduction where one currently does not exist
(2) Show significant reductions in emission levels of $NO_x$ achieved at a low capital and very low operating cost compared to the selective catalytic reduction (SCR) technology
(3) Show that there is no need for a supplemental fuel. Reburn will be carried out using coal, the present boiler fuel
(4) Provide a system that will maintain boiler reliability, operability, and steam production performance after retrofit

The overall project is 43 months in duration with an estimated total cost of $13.1 million at completion of Phase III -- Long Term Testing activities. The project participants which are providing the funding for the work are as follows:

- U.S. Department of Energy - 50% funding co-sponsor
- B&W - prime contractor and project manager
- WP&L - host site utility and funding co-sponsor

- Electric Power Research Institute (EPRI) - funding co-sponsor
- State of Illinois - funding co-sponsor
- Utility funding co-sponsors:
  (1) Allegheny Power System
  (2) Atlantic Electric
  (3) Associated Electric Co-op, Inc.
  (4) Baltimore Gas & Electric
  (5) Iowa Electric Light & Power Co.
  (6) Iowa Public Service
  (7) Kansas City Board of Public Utilities
  (8) Kansas City Power & Light
  (9) Missouri Public Service
  (10) Northern Indiana Public Service Company
  (11) Tampa Electric Company

## DESCRIPTION OF THE TECHNOLOGY

Coal reburning for Cyclone boiler $NO_x$ control technology combines pulverized coal combustion technology with existing Cyclone-fired technology to maintain the combustion efficiencies characteristic of Cyclone furnaces but at reduced $NO_x$ emissions. Accordingly, this combination allows the Cyclone operator to maintain 100% coal operation of the unit with the corresponding economic and availability benefits of coal.

Reburning is a process by which $NO_x$ produced in the Cyclone is reduced (decomposed to molecular nitrogen) in the main furnace by injection of a secondary fuel. The secondary (or "reburning") fuel creates an oxygen deficient (reducing) region which accomplishes decomposition of the $NO_x$.

The reburning process employs multiple combustion zones in the furnace to achieve $NO_x$ reduction (Figure 1). The Cyclones which make up the main combustion zone are operated at a reduced stoichiometry and have the majority of the fuel input (70 to 80% heat input). The majority of investigations on reburning technology have shown that the main combustion zone of the furnace should be operated at a stoichiometry of less than 1.0. This operating criteria is impractical for Cyclone units due to the potential for highly corrosive conditions, since most Cyclones burn high-sulfur, high-iron-content

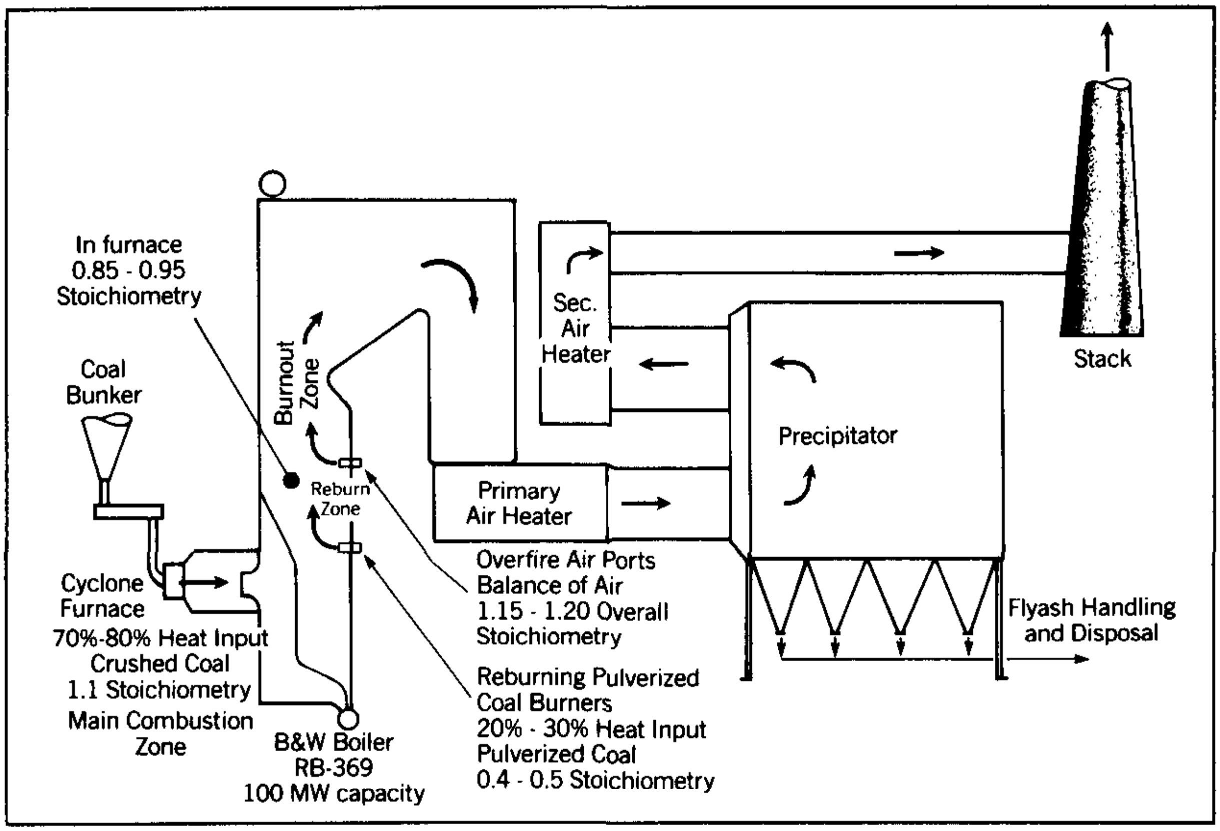


**Figure 1. Cyclone coal reburn project -- system layout.**

bituminous coals. To avoid this situation and its operating problems, the Cyclone main combustion zone should operate at a stoichiometry of no less than 1.1 (2% excess $O_2$).

The balance of fuel is introduced through reburning burners above the main combustion zone (Cyclones) in the reburning zone. To protect the tubes in the reburning zone from fireside corrosion, some air is introduced through these burners. The burners are operated in a similar fashion to a standard, wall-fired burner but at a reduced stoichiometry of 0.4 to 0.5. The furnace reburning zone, which contains a mixture of both Cyclone combustion gases and reburn burner gases, is operated at resulting mix stoichiometries in the range of 0.85 to 0.95 in order to achieve maximum $NO_x$ reduction.

The balance of the required combustion air (totaling 15 to 20% excess air at the economizer outlet) is introduced through overfire air ports. These ports are designed with adjustable air velocity control to enable optimization of mixing for complete fuel burnout prior to exiting the furnace.

## BACKGROUND

Boilers equipped with Cyclone furnaces have many important advantages over conventional pulverized-coal-fired boilers, such as the capability to burn a range of low-grade fuels and a simpler, more economical coal preparation and feeding system. However, Cyclone units utilize extremely fast mixing between the coal and combustion air and, therefore, promote well mixed combustion with inherent high temperatures and elevated $NO_x$ emissions. Thus, Cyclone boilers are prime candidates for mandated reduction in the emissions of $NO_x$. Currently there is no economical, proven, retrofit low $NO_x$ combustion control technology for Cyclone boilers.

The use of Selected Catalytic Reduction (SCR) technology offers the promise of controlling $NO_x$ from these units, but at high capital and operating costs. Reburning is, therefore, a promising alternative $NO_x$ reduction approach for Cyclone-equipped units at more reasonable operating cost. In addition, the previous attempts to apply staged combustion have not been successful due to operational problems (Cyclone corrosion).

Reburning can be applied while the Cyclone operates under its normal oxidizing condition, so its effects on Cyclone performance are minimized. Initial work performed on the reburn concept by B&W was a feasibility study for applying reburn technology to utility Cyclone-fired boilers, and the results were very encouraging. Based on the results of the feasibility analysis, an EPRI/Gas Research Institute (GRI) sponsored (EPRI RP-2154-11; GRI: 5087-254-1471) pilot-scale evaluation of Cyclone reburn was undertaken.[1] B&W's six million Btu/hr Small Boiler Simulator (SBS) located at it's Alliance Research Center was used to perform the pilot-scale Cyclone reburning tests. Three different reburning fuels -- natural gas, #6 oil, and pulverized coal -- were tried. The results indicate that 50 to 80% $NO_x$ reduction from baseline conditions can be achieved while using 15 to 25% of the total Btu input to the furnace as reburning fuel. Additionally, the tests revealed that the potential side effects of the technology (e.g., changes in combustion efficiency, deposition, and corrosion) would not adversely affect boiler performance. This research has also shown that coal as a reburning fuel performs nearly as well as gas or oil without deleterious effects on combustion efficiency. This result means that boilers using reburning for $NO_x$ control can maintain 100% coal usage instead of switching to 20% gas/oil for reburning.

The full-scale demonstration of coal reburning was the next step in technology development and resulted in this Clean Coal II project. It was necessary for the following reasons:

- Currently there is 26,000 MWe capacity of Cyclone-fired steam generating equipment in operation in the U.S., most of which is still burning coal
- Of the total $NO_x$ emissions from pre-NSPS coal-fired power stations in the U.S., 21% comes from Cyclone-fired boilers, and it is expected that 80 to 85% of the 26,000 MWe capacity can be retrofitted with coal reburning
- Estimates based on the pilot study are that coal reburning technology in Cyclone-fired boilers will economically achieve at least a 50% reduction in $NO_x$ emissions
- Coal reburning is not expected to adversely affect combustion efficiency, deposition, corrosion, and overall boiler performance
- Using coal as the Cyclone reburning fuel for $NO_x$ control, as opposed to oil or gas, makes it unnecessary to add alternative costly fuels to many plants
- Assuming an average emissions rate of 1100 ppm $NO_x$, the annual Cyclone boiler emissions, for all 26,000 MWe, would be approximately 1,200,000 ton/yr. A 50% reduction at 85% of these units would reduce $NO_x$ emissions (as $NO_2$) by 500,000 ton/yr.

## TECHNOLOGY RETROFIT

Retrofit of the coal reburning technology to the Nelson Dewey Unit No. 2 boiler consisted of installation of the following equipment:

(1) **Four B&W S-type burners** - These were installed on the rear furnace wall and are spaced on seven ft centers

(2) **Four B&W dual zone overfire air ports** - These were also installed on the rear furnace wall approximately 16 ft above the burners. The ports provide the balance of air to complete the combustion process

(3) **Reburn coal handling system** - This consists of a modification to the existing tripper conveyor system to divert coal to the reburn system, a 150 ton coal silo, and a gravimetric coal feeder to deliver coal to the pulverizer

(4) **MPS67 pulverizer** - This unit prepares coal to be delivered to each of the four reburn burners. Coal can be pulverized to as fine as 90% through 200 mesh. The pulverizer is equipped with a rotating classifier to improve fineness of grind and an automatic hydraulic loading system to provide variable pressure to the grinding elements inside the pulverizer to eliminate vibration at low load operation

(5) **Primary air fan** - The fan provides hot primary air from the air heater outlet to the pulverizer to dry the coal and pneumatically convey the pulverized product to each of the reburn burners

(6) **Pulverizer enclosure** - An enclosure was erected adjacent to the existing power house to serve as the pulverizer building as well as structural support for the coal silo

(7) **Furnace pressure part modifications** - Installation of the burners and overfire air ports required a total of eight penetrations into the furnace

(8) **Control system modifications** - An upgrade of the Nelson Dewey Bailey Net 90 control system was carried out to control the coal reburning system. The reburn control system was interfaced with the existing boiler controls to allow automatic operation of the boiler with reburn in service. Also, the control room panel board was modified to make room for reburn controls

(9) **Electrical equipment** - A new 4160V circuit breaker was supplied by WP&L to service the reburn system. A 4160V/480V stepdown transformer was also installed to provide power to the new reburn 480/V motor control center

(10) **Duct work** - A primary air duct to the primary air fan inlet, a tempering air duct from the forced draft fan to the primary air fan inlet, a secondary air duct to the burners, a flue gas recirculation duct to the burners, and an overfire air duct to supply air to the overfire air ports were all installed

(11) **Flow control** - Air flow monitors, dampers, and damper drives were installed in the new ducts to monitor and control flow

(12) **Auxiliary systems** - Service water, fire protection, instrument air, service air, seal air, etc. were also provided

Figure 2 is an isometric view of the system giving the spacial relationships of each of the components of the system. Integration of the reburn system with the existing plant consisted of interfaces with the coal feed tripper conveyor, the air heater outlet, flue gas recirculation system, forced draft fan discharge, hot air recirculation system, penetrations into the boiler, and the control system. Accordingly, installation of the reburn system was carried out in three steps, the first of which was the spring outage from March 11 through 21, 1991 when all asbestos removal as well as tie-ins for auxiliary systems such as

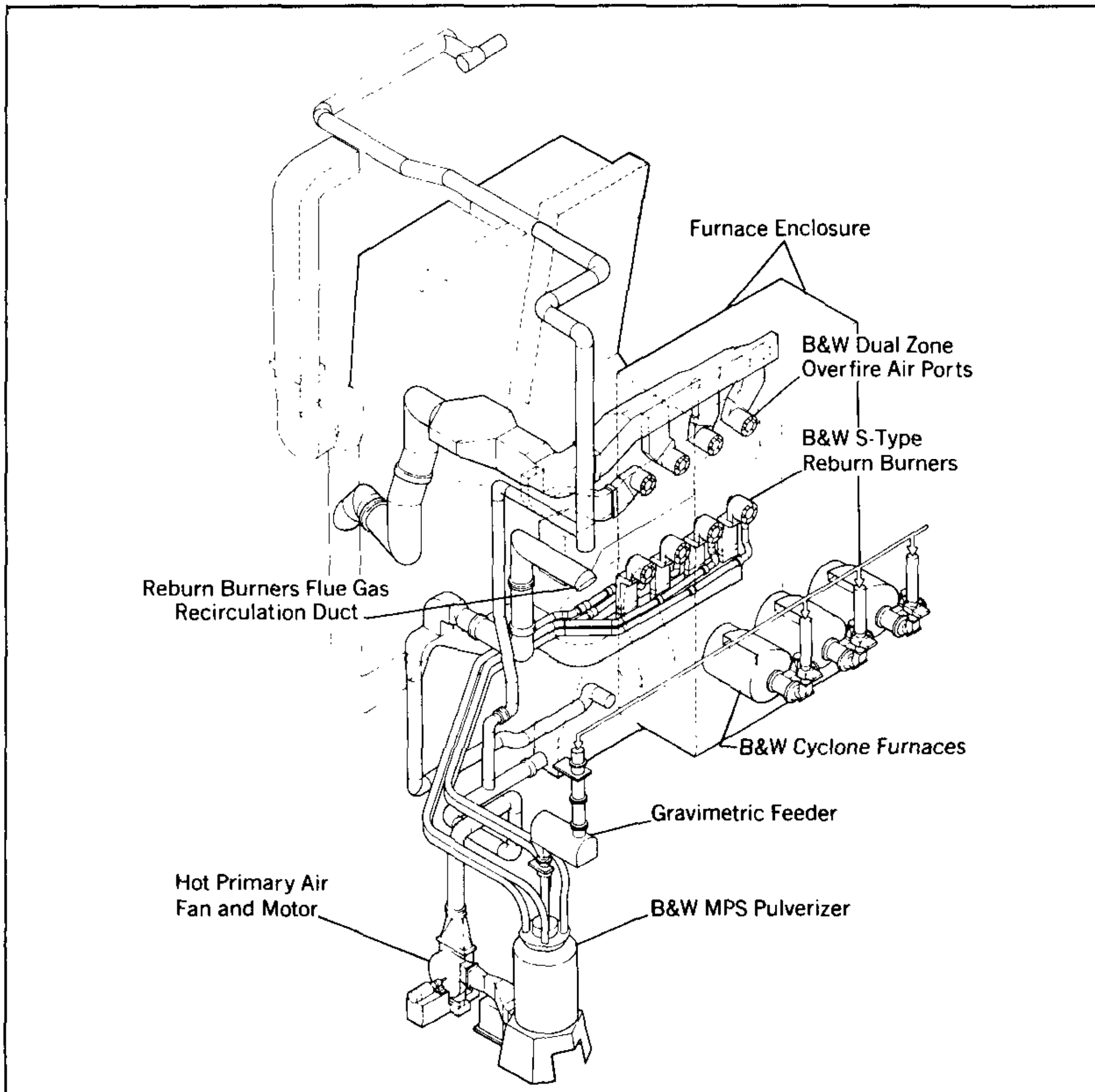


**Figure 2. Isometric view, coal reburning for Cyclone boiler $NO_x$ control.**

service water, station air, etc. were completed. The second step was from June 1 through September 16, 1991 when all aspects of system construction which did not require a boiler outage were completed. This included the enclosure, pulverizer, silo, feeder, and all flue and duct work up to the tie-in points. The remainder of construction, including burner and overfire air installation and all tie-ins were completed during the fall boiler outage, September 16 through October 31, 1991. Through use of this plan, there was minimal interference with boiler operation.

## PROJECT SCHEDULE

Coal Reburning Demonstration for Cyclone Boiler $NO_x$ Control is scheduled to last a total of 43 months, ending in March 1993 and consisting of three phases of activities (see Figure 3).

Phase I -- Design and Permitting entailed mathematical and cold flow modeling as well as pilot-scale testing in the six million Btu/hr Small Boiler Simulator at B&W's Alliance

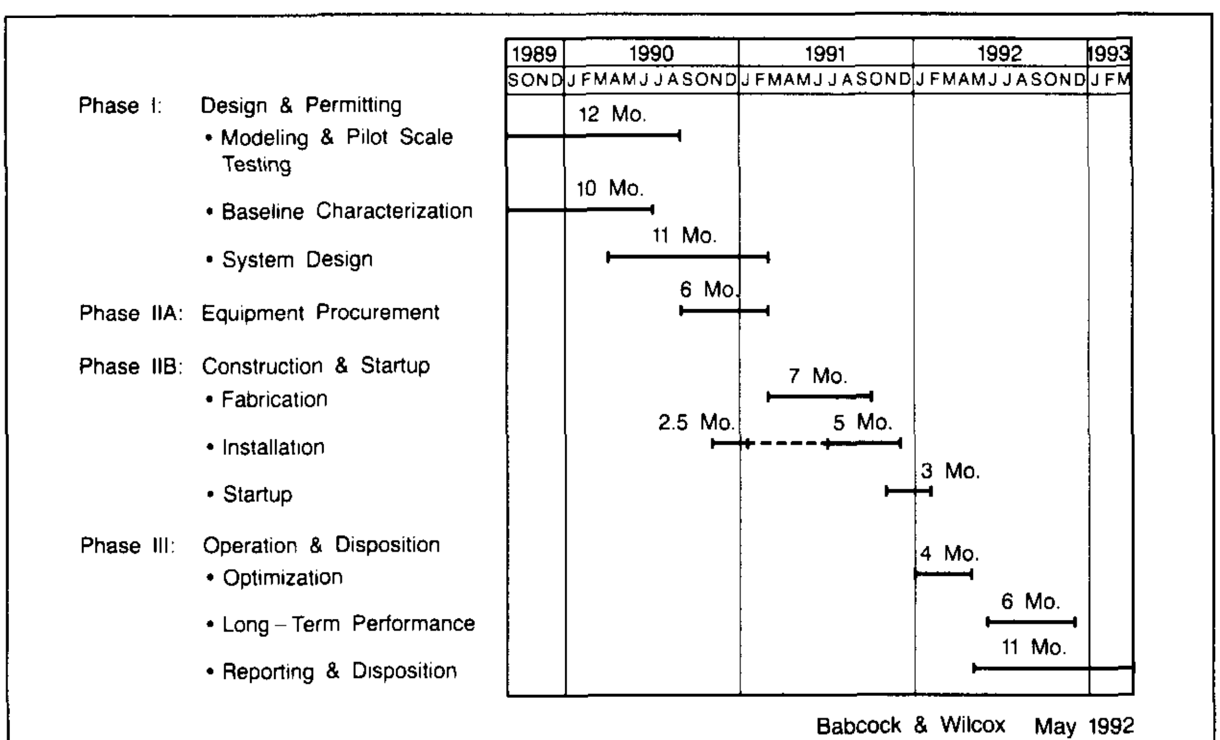


**Figure 3. Project schedule.**

Research Center. In addition, baseline testing of the unit was carried out in April and May 1990 to characterize pre-retrofit operation. Velocity and temperature profiles were developed during baseline testing to allow validation of the mathematical and cold flow models.[2] This information and results developed with the models were used in the design of the system. Phase I was completed in February 1991.

Phase II was divided into Phase IIA -- Equipment Procurement of Long-Lead-Time Items as part of budget period one, and Phase IIB -- Construction and Startup. Construction activities were completed in November 1991 with startup initiated immediately thereafter. Startup activities were essentially completed in February 1992 with the exception of operation in the fully automatic mode. Full automatic operation was achieved in early May.

Phase III -- Operation and Disposition was initiated in January 1992 with preparation for testing. Parametric optimization testing was started in February and completed in May. Subsequently long-term performance testing, where the system is operated on a day-to-day, load following basis with the optimum settings developed during parametric optimization testing, was begun and is currently under way. Long-term testing should be completed during the third quarter of 1992 with only report writing remaining to complete the project.

## PRELIMINARY RESULTS AT NELSON DEWEY UNIT NO. 2

The focus of this demonstration project's testing program was to determine the maximum $NO_x$ reduction capabilities possible, without adversely impacting plant performance, operation, or maintenance. In particular, the prototype evaluations were compared to confirm and expand upon the results of the Small Boiler Simulator pilot test programs.

### Test Plan Variables

Numerous variables are associated with the reburn system and a day-to-day test matrix was set up to proceed from one parameter to another during parametric optimization testing. All reburn performance testing has been carried out using Lamar coal from Indiana, and having a medium sulfur content (1.8%). The test variables included in the matrix along with the range tested are:

(1) Reburn burner stoichiometry ($\approx$0.35 to 0.70)
(2) Percent of heat input through the reburn system ($\approx$25 to 35%)
(3) Reburn zone stoichiometry (0.85 to 0.95)
(4) Fineness of pulverized coal to the burners (75% $\leq$ 200 mesh to 96% < 200 mesh)
(5) Burner spin vane and impeller adjustments
(6) Overfire air port spin vane/sliding disk adjustments
(7) Boiler load (40 MW to 110 MW)
(8) Economizer outlet $O_2$% (2 to 4%)
(9) Gas recirculation rates to the reburn burners (0 to 4%)

Information collected to evaluate performance of the technology is as follows:

(1) Impact on $NO_x$ reduction of the test variables itemized above
(2) Furnace temperature and heat absorption profiles
(3) Unburned combustibles loss
(4) Boiler thermal efficiency
(5) Corrosion potential
(6) Slagging and fouling
(7) Electrostatic precipitator operation
(8) Operations experience

During parametric optimization testing, a total of approximately 90 test conditions were investigated while using Lamar coal, an Indiana, medium sulfur, bituminous coal. Sample and data analyses are under way but are not complete. Preliminary results are presented here.

## $NO_x$ Emissions

Emissions of $NO_x$ during operation of the coal reburning system are reduced by 35 to 60% from baseline test levels ($NO_x$ levels without reburn, same day, same load) over the range of operating conditions evaluated.

Figure 4 represents $NO_x$ emissions in parts per million (ppm), corrected to 3% $O_2$, as a function of reburn zone stoichiometry, all at full load (110 MW). As can be seen in the

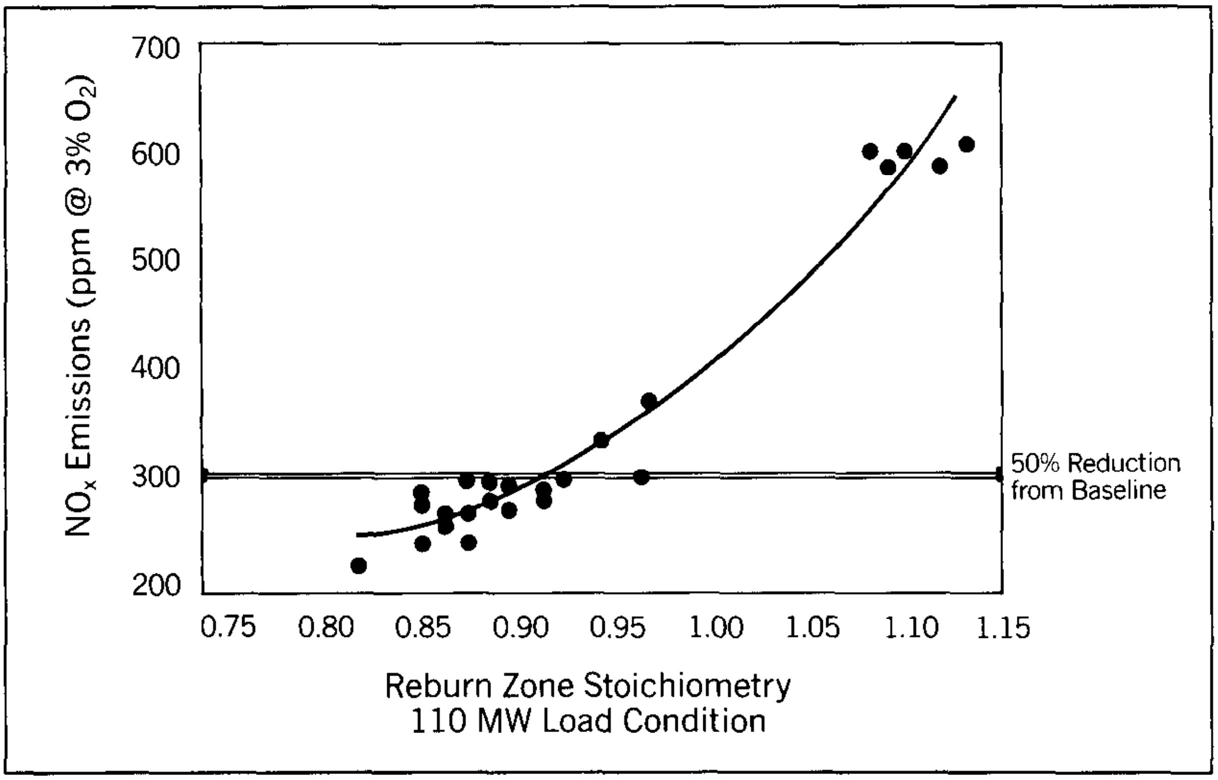


**Figure 4. $NO_x$ emissions vs. reburn zone stoichiometry.**

figure, $NO_x$ is reduced from 609 ppm down to 233 ppm over the range of 1.15 to 0.83 in reburn zone stoichiometry. Reductions 50% or greater are achieved below a stoichiometry of approximately 0.92. During these tests at full load, Cyclone stoichiometry is maintained as close to 1.1 (10% excess air) as possible to minimize potential Cyclone operating concerns.

Figure 5 presents the preliminary results for $NO_x$ emission levels as a function of load (110 to 40 MW). These data were collected during performance testing operation in the fully automatic control mode. Reductions in $NO_x$ of greater than 50% are achieved from 110 MW to approximately 70 MW (64% of full load). Below 70 MW, $NO_x$ reductions varied between 35 to 50% because of the operating conditions required to matintain reburning stability.

The automatic control system has been tuned to maximize $NO_x$ reduction while avoiding operation on the edge of other problems which would result due to air/fuel flow upsets.

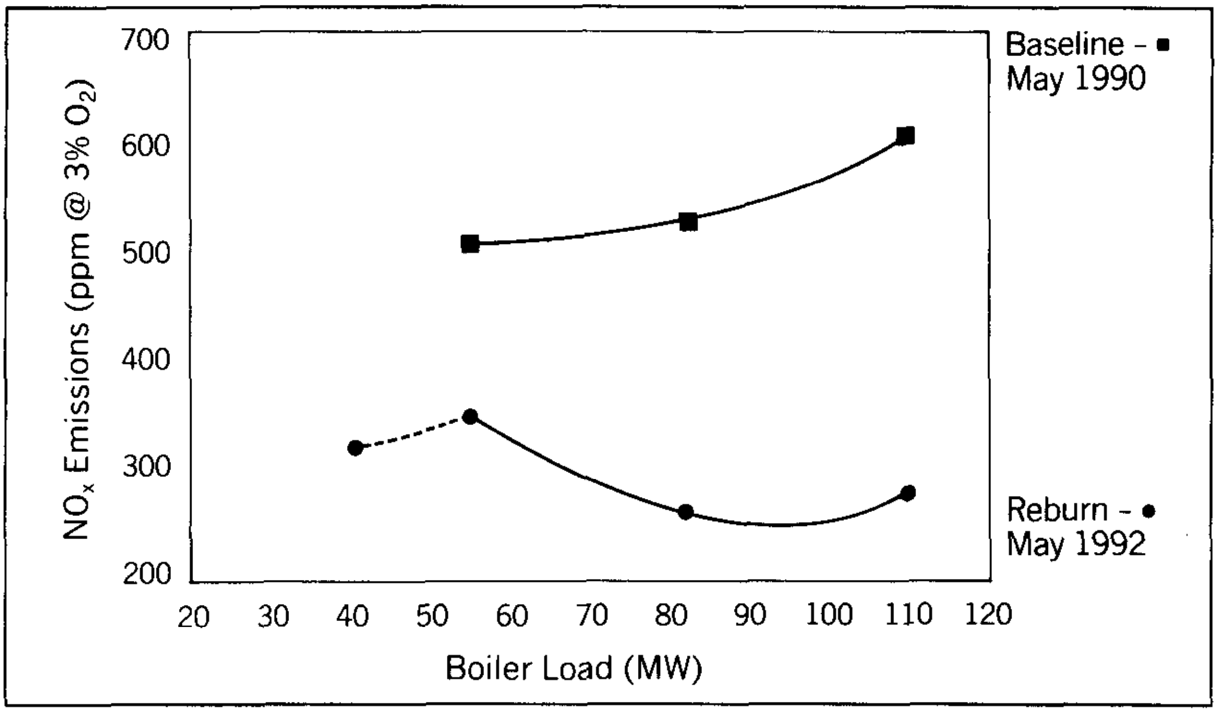


**Figure 5. $NO_x$ emissions vs. load.**

High carbon monoxide (CO) or unburned carbon emission levels can result if air/fuel imbalances occur during operation. To avoid such problems, a safety margin is designed into the automatic control system in order to accomodate the day-to-day boiler operation.

Finally, it should be noted the reburn system is operated down to a unit load of 40 MW in the automatic mode. $NO_x$ emission levels are about 324 ppm (corrected to 3% $O_2$) at the low load but an exact percent reduction is unclear since baseline $NO_x$ emissions at this low load were never measured. Additionally, work is continuing in order to improve the $NO_x$ reduction at the lower loads via reducing cooling air flows to idle Cyclones.

## Furnace Exit Gas Temperature

Furnace exit gas temperature (FEGT) has changed from baseline to reburning operation. At full load with reburn in operation, a reduction in FEGT is observed. The difference between baseline FEGT and reburn values vary between approximately 50 and 150F. This effect becomes less significant at lower loads.

The rational for this effect is under examination via mathematical modeling studies. It is reproducible and consistent with reburn in operation. Whether or not it can be expected in other Cyclone units remains to be determined via ongoing analyses and may not be ascertained until future Cyclone reburn retrofits confirm the phenomenon.

**Unburned Combustibles Loss**

Preliminary analyses indicate that there is an impact on unburned carbon (UBC) loss in the precipitator ash. Baseline measures of carbon in the ash ranged from 9% at 4% excess $O_2$ to 18% at 2% excess $O_2$ at full load. With reburn in operation, UBC levels range from about 13 to 22%. Boiler efficiency loss due to the increase in UBC during Cyclonce coal reburning is explained by the typically low baseline ash loading and the inherent increase in ash loading when reburning coal. Quantifying this effect has not, as yet, been completed since data variability from day-to-day under similar operating conditions has occurred. Particulate loadings at the precipitator inlet and carbon content of the collected ash are being reviewed to develop a correlation. Worst case impact on boiler efficiency will be discussed below.

The reburn process does not appear to have a major adverse impact on CO generation under optimum operating conditions. Flue gas CO concentrations are generally less than 100 ppm with reburn in operation, not significantly different than baseline levels.

**Boiler Thermal Efficiency**

Preliminary analyses indicate that boiler thermal efficiency with reburn in operation is adversely impacted by UBC loss in the ash. An efficiency loss of approximately 0.3 to 0.7% due to reburn operation UBC loss has been determined at full load. Overall, at full load, boiler efficiency during baseline testing averaged about 88.16%. With reburn in operation, boiler efficiency averaged between 87.5 to 88.1%. These efficiencies are presently being reviewed to assure that no other parameters have changed to mask the effects of reburning operation.

At lower loads, an efficiency loss of approximately 0.8 to 1.5% has been determined on a preliminary basis.

## Corrosion Potential

As part of the project's commitment to investigate possible corrosion problems as a result of the reducing atmosphere in the areas of the burners, ultrasonic thickness testing of the furnace wall tubes was conducted prior to reburn system startup. Readings were taken at five elevations on each of the four walls of the furnace for a total of approximately 1800 measurements. Results of the testing indicated the furnace walls have experienced negligible wall thinning since original startup in 1961. None of the inspected tubes were below B&W wall thickness guidelines for required repair. In September/October 1992, this testing will be repeated to determine if a corrosion problem exists with reburn system operation.

To further evaluate the corrosion potential and possible solutions, two bi-metallic (carbon steel with a stainless cladding) furnace wall throat openings were installed to monitor the affects of the reducing atmosphere at the reburn burner throat region on two of the four burners. The other two burner throat regions were made of standard carbon steel tubes. Impact of the reducing atmosphere, if any, on the two materials will be established. Additionally, thicker tube wall samples are located at various locations within the lower furnace region to assess simulated higher tube wall temperatures on corrosion rate.

As a possible indication of corrosion potential, measurements of hydrogen sulfide ($H_2S$) concentration at the walls of the furnace in the reburn zone have been made during testing. No significant levels of $H_2S$ have been detected thus far.

## Slagging and Fouling

Minimal changes in slagging and fouling characteristics were expected as a result of reburn operation. However, WP&L has indicated that the unit now appears cleaner in the convection pass areas, based on a recent outage and inspection, than was previously the case. Since FEGT has decreased, no additional major slagging problems have been encountered. Due to the higher dust loading conditions with reburning, sootblowing cycles were monitored, but no increase in frequency or capacity has yet been required.

## Precipitator Performance

Precipitator particulate collection performance has apparently not degraded due to reburn operation. Additionally, under normal circumstances, opacity improves slightly. Actual inlet and outlet dust loadings, as well as ash resistivity data, are not yet available. This *information will be used to quantify precipitator performance with the reburn* system in operation. Based on observations to date, no significant adverse impact is expected to be seen in the data.

## Operations Experience

Smooth transition from non-reburn to reburn operation has been WP&L's experience thus far. This observation, in conjunction with no additional problems with precipitator performance, slagging/fouling, and FEGT, make the reburn system an acceptable system to date.

Figure 6, developed from the data acquisition system in the control room, illustrates the effect of reburn operation on $NO_x$ and CO emissions versus boiler load capability. As can be seen in the figure, boiler load was increased to full load at about 7:15 am and remained there for reburn testing, initiated at about 9:45 am. When the reburn system was started, no interruption of unit generating capacity was encountered. Emissions of $NO_x$ fell from the 600 ppm level down to the 260 ppm range for a total $NO_x$ reduction of about 57%. During the same time frame, CO emissions remained relatively constant, below 100 ppm.

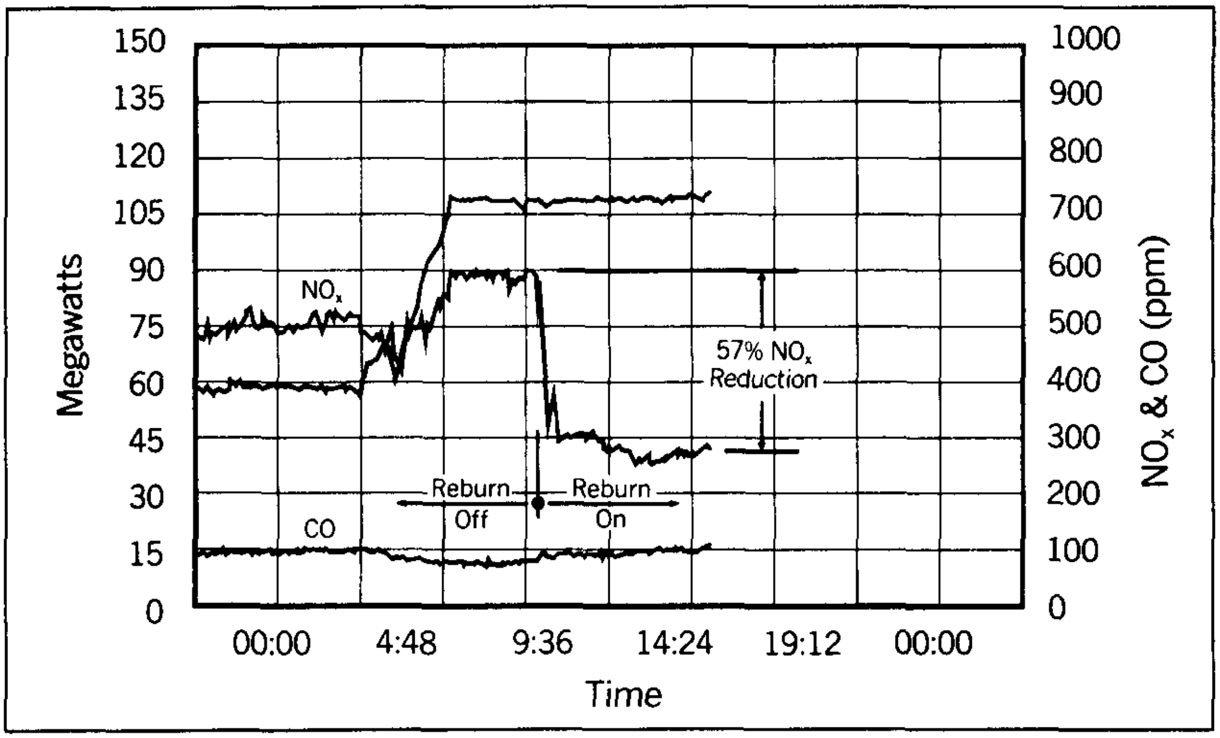


**Figure 6. Effect of reburn system operation on $NO_x$ and CO emissions vs. load.**

## MARKET POTENTIAL

Currently, 105 operating, Cyclone-equipped utility boilers exist. They are located primarily in the Midwest and/or in ozone non-attainment regions. These units represent approximately 15% of pre-New Source Performance Standards (NSPS) coal-fired generating capacity (over 26,000 MW). However, they contribute approximately 21% of the total $NO_x$ emitted from coal-fired units. Although the majority of the Cyclone units are 20 to 30 years old, utilities plan to operate many of them for at least an additional 10 to 20 years.

Cyclones are characterized by high temperature, high efficiency, high turbulence, and high $NO_x$-generating combustion flame patterns. $NO_x$ and volatile organic compounds (VOC) are considered to be precursors to ozone ($O_3$) and it is believed that one of the most cost effective methods of reducing ozone in non-attainment areas is to reduce $NO_x$ emissions from stationary sources. Title I of the Clean Air Act Amendments of 1990 is Attainment and Maintenance of Ambient Air Quality Standards, and has a goal of reducing ozone to 0.12 ppm, or lower as measured on an hourly basis. It will be implemented in five phases over 20 years. While the dates and regions are well defined, the actual $NO_x$ limits and methods to achieve them have been left purposely open-ended. $NO_x$ limits may be assigned on a case-by-case basis with Reasonable Available Control Technology (RACT) influencing those decisions. Title I (ozone non-attainment) will require 1993 and 1996 $NO_x$ reductions on Cyclone units in specific geographic locations. Those Cyclone units not affected by Title I will come under Title IV--Acid Decomposition Control $NO_x$ limits which will be released in 1997.

The major objective of this project is to develop Cyclone reburn technology to the point where it can be offered to utility and industrial Cyclone operators as a low-cost, easily retrofitted pollution control alternative to help address the need to reduce atmospheric emissions and to meet regulatory requirements.

## SUMMARY

The "Demonstration of Coal Reburning for Cyclone Boiler $NO_x$ Control" project, as part of DOE Clean Coal II program, has completed Phase I -- System Design, Phase II -- Procurement, Construction and Startup and is now engaged in Phase III -- Testing activities. Operation to date has achieved the goals of the project with $NO_x$ reductions in excess of 50%. No major adverse side effects on Cyclone furnace operation and slag tapping are apparent except for an increase in unburned carbon content of the precipitator ash which must yet be quantified.

All outstanding long-term performance issues are currently being addressed in Phase III -- Long Term Testing. This work is necessary to assure that impacts of coal reburning on items such as unburned carbon, corrosion, particulate removal, boiler cleanliness, etc. are understood not on a short-term basis alone, but over longer periods of time. Also, system operability including load following performance must be evaluated before the technology can be considered commercially ready.

**REFERENCES**

(1) Farzan, H., *et al.*, "Pilot Evaluation of Reburning for Cyclone Boiler $NO_x$ Control," 1989, EPRI/EPA Joint Symposium on Stationary Combustion $NO_x$ Control, San Francisco, California, March 6-9, 1989.

(2) Yagiela, A.S., *et al.*, "Update on Coal Reburning Technology for Reducing $NO_x$ in Cyclone Boilers," American Power Conference, Chicago, Illinois, April 29-30, 1991.

**Legal Notice:**

**Table 1**
Boiler Information - Nelson Dewey, Unit 2

| | |
|---|---|
| Name Plate Rate | 100 MWe |
| Type | Steam Turbine |
| Primary Fuel | Bituminous and Subbituminous Coal |
| Operation Date | October 1962 - Unit No. 2 |
| Boiler ID | B&W RB-369 |
| Boiler Capacity | Nominal 110 MWe |
| Boiler General Condition | Good |
| Boiler Manufacturer | Babcock & Wilcox |
| Boiler Type | Cyclone Fired RB Boiler, Pressurized |
| Reburning Demonstration Fuel | Indiana (Lamar) Bituminous Coal, Medium Sulfur (1.87%) |
| Burners | Three B&W Vortex-Type Burners, Single-Wall Fired |
| Particulate Control | Research Cottrell ESP |
| Boiler Availability | 90% Availability |

# Gas Reburning for Combined $NO_x$ and $SO_2$ Emission Control on Utility Boilers

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October 18-20, 1992
San Francisco, California

Abstract:

This paper describes two demonstrations of Gas Reburning integrated with Sorbent-Injection for combined $NO_x$ and $SO_2$ control on utility boiler systems. The technical progress from demonstrations on tangentially- and cyclone-fired systems are presented. To date approximately 1500 hours of operation have been completed in long-term, field testing on an 80 MW tangentially-fired unit retrofitted with a Gas Reburning-Sorbent Injection (GR-SI) system. Results have shown that $NO_x$ and $SO_2$ reductions have exceeded the program goals of 60 and 50 percent reduction, respectively, without adverse impact on boiler performance.

## INTRODUCTION

Passage of the 1990 Clean Air Act Amendments has underscored the need for establishing commercially acceptable technologies for reducing Sulfur Dioxide ($SO_2$) and Nitrogen Oxide ($NO_x$) emissions. This paper describes two demonstrations of Gas Reburning integrated with Sorbent Injection for combined $NO_x$ and $SO_2$ control on utility boiler systems.

Gas Reburning is a combustion modification control technology. It can be retrofitted to virtually any combustion system. An appropriate amount of natural gas (typically 10-20% of the total heat input) is injected into the furnace above the main burners producing a slightly reducing zone. $NO_x$ is reduced in this zone by reactions with hydrocarbon fragments. Additional overfire air is provided to burn out the remaining combustibles. Gas Reburning alone can reduce $NO_x$ and $SO_2$ emissions by 60 and 20 percent, respectively. The $SO_2$ reduction is due to the negligible sulfur content of natural gas.

Gas Reburning may be integrated with a wide range of emission control technologies to enhance emission control performance. Combined with Sorbent Injection, $SO_2$ reductions of 50% or higher appear achievable. Demonstration of these integrated technologies are now in progress under the Department of Energy's Clean Coal Technology Program.

With Gas Reburning-Sorbent Injection (GR-SI), $NO_x$ and $SO_2$ emission targets are 60 and 50 percent respectively. GR-SI is being demonstrated on an 80MW tangentially-fired boiler and a 40 MW cyclone-fired boiler. Tests are in progress on the tangentially-fired boiler and early results showed that NOx reductions up to 77% could be achieved in short term tests. Subsequent tests have shown that the project goal of 60% can be achieved during routine operation with no significant effects on boiler performance. Long term operation has been established at 65% reduction with $NO_x$ emissions reduced to 0.25 lb/$10^6$ Btu. The cyclone unit will begin parametric testing in the Winter of 1992.

The GR-SI project is co-funded by the U.S. Department of Energy (Pittsburgh Energy Technology Center), the Gas Research Institute and the State of Illinois Department of Energy and Natural Resources.

## GAS REBURNING

The concept of $NO_x$ reduction by flames has been recognized for over a decade.[1,2] In the United States, experimental studies of reburning technology are being supported by the Gas Research Institute,[3-5] the United States Environmental Protection Agency, the Department of Energy and the Electric Power Research Institute. Reburning for in-furnace $NO_x$ control has been applied to coal-fired boilers in Japan[6] and the United States,[7] and to a municipal waste incinerator in the United States.[8]

Figure 1 illustrates the basic reburning process with natural gas as the reburning fuel. The overall process can be divided conceptually into three zones:

**Primary Combustion Zone.** The heat released in this zone normally accounts for 80 to 85 percent of the total heat input to the combustion system. The main fuel is burned under fuel-lean conditions resulting in the formation of $NO_x$.

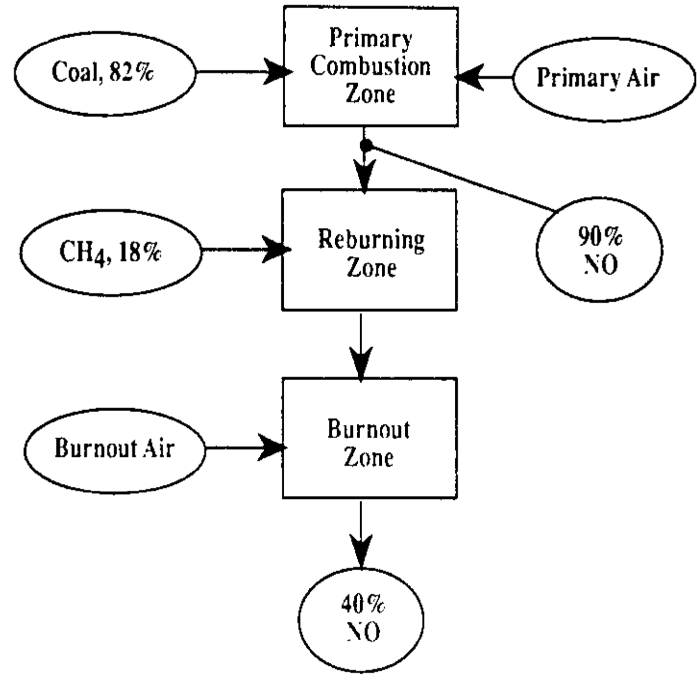


Figure 1. Gas Reburning Process.

**Reburning Zone.** The reburning fuel, which accounts for the other 15 to 20 percent of the fuel heat input, is injected downstream of the primary zone in sufficient quantity to form a slightly fuel rich zone where $NO_x$ from the primary zone is reduced. In the reburning zone, hydrocarbon fragments produced by the partial oxidation of the reburning fuel (primarily CH-radicals) reduce the primary $NO_x$ to HCN, which is almost immediately converted to molecular nitrogen and other nitrogenous species. When the reburning fuel is fully consumed, a small fraction of the HCN and $NH_3$ intermediates remains "frozen", and persists through the remainder of the reburning zone.

**Burnout Zone.** In the third and final zone, additional combustion air is added to oxidize carbon monoxide and any remaining fuel fragments and to produce overall fuel-lean conditions. The remaining reduced nitrogen species are generally oxidized to NO.

Extensive bench and pilot scale tests have been conducted to compare the performance of alternate reburning fuels and to evaluate $NO_x$ control effectiveness and process design considerations.[4] The results of these studies have shown that the key parameters which influence the effectiveness of the reburning process are the zone operating stoichiometries, furnace gas temperatures, zone residence times, and reburning fuel mixing. The results of small-scale studies have also shown that reburning with natural gas is more effective than reburning with other fuels, particularly at low baseline $NO_x$ levels. Natural gas is also the preferred reburning fuel when available furnace residence time is limited. The remainder of this paper focuses on natural gas as the reburning fuel and the resulting technology is termed "Gas Reburning".

In a utility boiler, Gas Reburning is applied in the furnace between the main combustion equipment and convective heat transfer sections. Since the main combustion equipment does not need to be altered, Gas Reburning is compatible with all firing types, including wall, tangential, cyclone and stoker configurations. Figure 2 illustrates the typical retrofit of Gas Reburning to a tangentially fired boiler. At normal or baseline operating conditions, all of the coal is fired through the existing burners. For Gas Reburning, the thermal input from coal firing is reduced by approximately 18 percent, but no changes to the firing system are required. The burners are simply operated at slightly lower load and the lowest excess air compatible with the burner and furnace designs. Operation at the lower thermal load and excess air also results in a reduction in the primary zone $NO_x$ emissions.

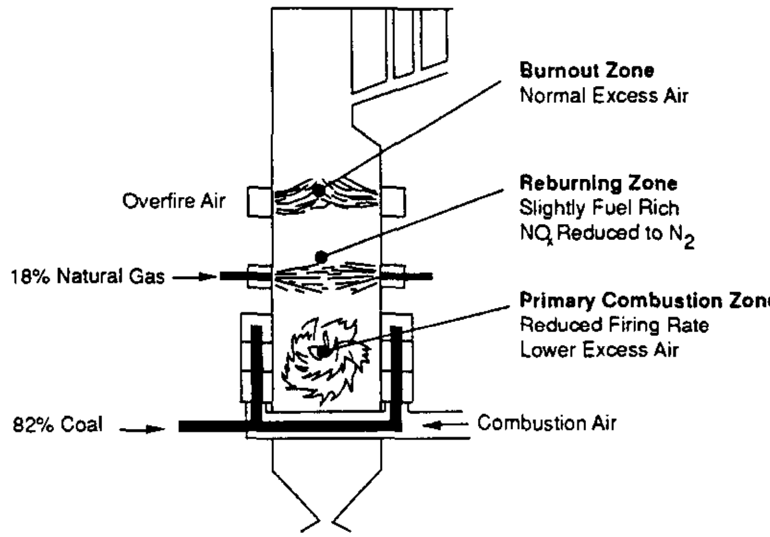


**Figure 2. Application of Gas Reburning technology to a tangentially fired utility boiler.**

Natural gas is injected above the burners to form the reburning zone. It is important to note that the gas injectors are not burners. They simply inject natural gas into the furnace without air. Since the mass flow of the gas which is used is relatively small, it is necessary in some applications to use a carrier gas to provide sufficient momentum for mixing the natural gas across the furnace width. A small quantity of recirculated flue gas, approximately 2-4 percent, is ideal since it has little excess oxygen. Minimizing excess oxygen in the reburning zone decreases the natural gas required to achieve the desired slightly fuel-rich conditions.

To complete combustion, overfire air is added above the reburning zone. The design of the overfire air system is conventional except that the amount of air required is greater than for conventional overfire air systems.

## Gas Reburning - Sorbent Injection

Gas Reburning alone can reduce $NO_x$ and $SO_2$ emissions by approximately 60 and 20 percent, respectively. Higher levels of control can be achieved by integrating Gas Reburning with Sorbent Injection for additional sulfur dioxide control. The reactions between sulfur and calcium compounds are well known and have formed the basis of several sulfur dioxide emission control technologies. Sorbent injection is one of these technologies. A calcium-based sorbent is injected into the combustion products as a powder where it reacts with sulfur dioxide to form calcium sulfate ($CaSO_4$). The reactions can proceed in any of three temperature "windows" which, for a coal-fired utility boiler, correspond to thermal conditions in the upper furnace (1260°C), economizer (540°C), and flue gas duct (150°C).

Upper furnace Sorbent Injection has been studied extensively in small scale studies,[3] in a recent field demonstration[9] and is being evaluated in this project. In this process, the sorbent is pneumatically transported and injected into the upper furnace region of a coal-fired boiler. The ideal location depends on the temperature, but generally corresponds to the region just prior to the entrance of the convective heat transfer sections. A range of calcium-based sorbents can be used. Limestone (calcium carbonate) is the lowest cost material, but also has the lowest reactivity. Dolomite is more reactive, but the mass of material required is larger due to the magnesium content. The preferred sorbent is calcium hydroxide which has the highest reactivity and produces the greatest sulfur dioxide reduction per mass of sorbent injected.

Upon injection, the calcium hydroxide immediately dehydrates to form a high surface area calcium oxide which reacts readily with sulfur dioxide and oxygen as well as sulfur trioxide to form calcium sulfate, a dry powder which remains suspended in the flue gas and is transported out of the boiler to the dust collector where it is captured with the flyash.

Gas Reburning and Sorbent Injection can be applied together to achieve combined $NO_x$ and $SO_2$ control in an easily retrofitted, low cost system. The Gas Reburning and Sorbent Injection processes are complementary. Since their application does not depend on the characteristics of the primary coal combustion system, they are applicable to virtually any coal-fired boiler including stokers, cyclones, or pulverized coal-fired equipment. Of course, the retrofit equipment must be designed within the specific constraints of the existing furnace and this requires a site-specific optimization.

The combined technology is termed "Gas Reburning-Sorbent Injection" or GR-SI. The Gas Reburning system alone achieves an incremental reduction in sulfur dioxide emissions, since natural gas contains no sulfur. This complements the reduction in sulfur dioxide produced with Sorbent Injection and lessens the need for dust collector upgrades. The emission control effectiveness of GR-SI depends to some extent on the design of the boiler. However GR-SI systems have been designed for three utility boilers with widely varying characteristics and emission reductions of greater than 60 and 50 percent have been projected for $NO_x$ and $SO_2$, respectively.

## DEMONSTRATIONS

Energy and Environmental Research Corporation (EER) is conducting demonstrations of integrated GR-SI systems on two coal-fired utility boilers[11-13] as part of the Department of Energy's Clean Coal Technology Program as summarized below:

- Tangential Fired Boiler at Hennepin Station. Unit 1, an 80 MW unit owned and operated by Illinois Power.

- Cyclone Fired Boiler at Lakeside Station. Unit 7, a 40 MW unit owned and operated by City Water, Light and Power, the municipal utility of the City of Springfield, Illinois.

Together, these two projects will provide data on the application of GR-SI to two major utility boiler firing configurations. The objective is to provide a data base which will: (1) demonstrate the emission control, performance impacts and cost effectiveness for two specific units, and (2) provide a data base for projecting performance to the full range of coal-fired utility boilers.

These projects are now in progress. The GR-SI system for the tangentially fired unit was installed first. The installation and optimization testing have been completed and the long term testing of the GR-SI system is in progress. The GR-SI system on the cyclone is under construction and start-up is scheduled for Winter of 1992.

## SYSTEM DESIGN AND PERFORMANCE PROJECTIONS

### Gas Reburning - Sorbent Injection

An overview of the GR-SI system installed on one of the two host units of this project is shown in Figure 3. The installed equipment consists of a gas reburning system, a sorbent injection system, and a humidification system for enhancement of the electrostatic precipitator (ESP) performance during sorbent injection. The total retrofit includes boiler pressure part modifications, duct modifications, and the installation of the GR-SI equipment and piping.

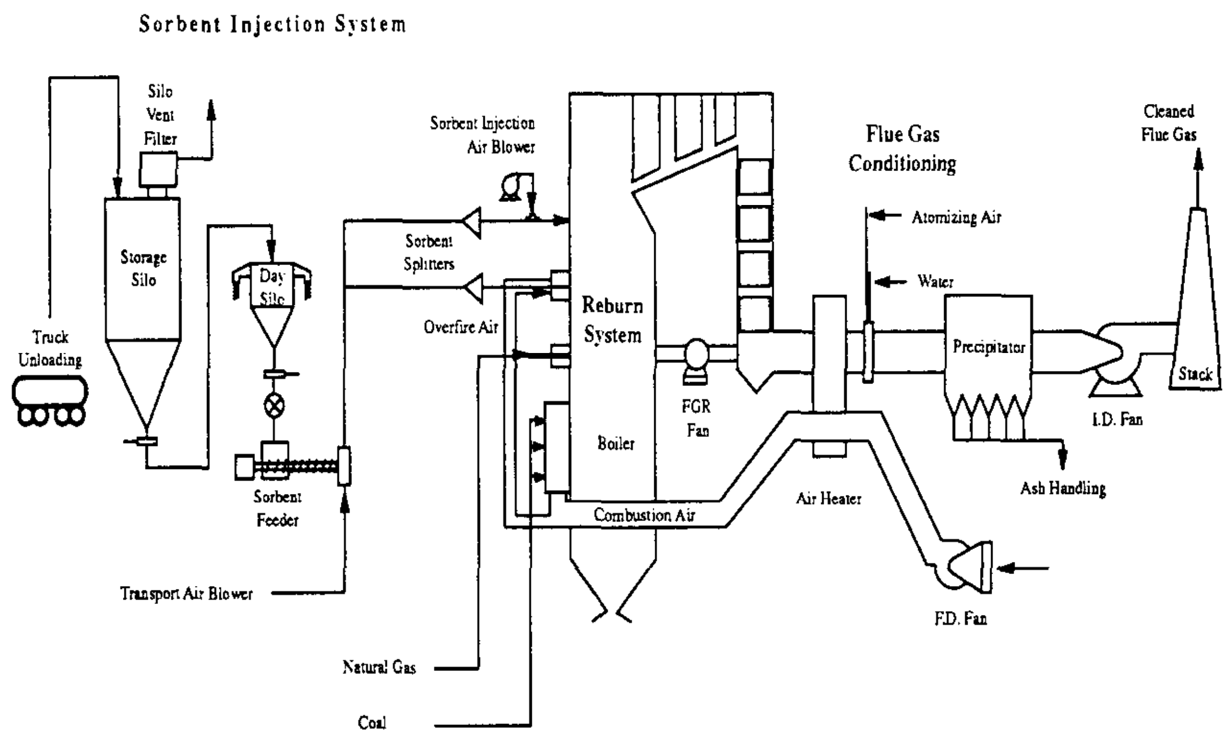


**Figure 3. Overview of GR–SI process as applied to a coal–fired utility boiler.**

The exact injection configurations for the reburning fuel, overfire air, and sorbent are highly site specific and are based on detailed engineering studies. These studies include baseline tests to establish general operational parameters, fabrication and testing of a scale physical model for isothermal flow tests, combustion and heat transfer modelling, and process modelling to develop projections of $NO_x$ and $SO_2$ removal performance.

The design of the GR-SI systems for the tangentially and cyclone fired units, illustrated in Figure 4, is described in the following. Configurations appropriate for other boiler designs could be substantially different.

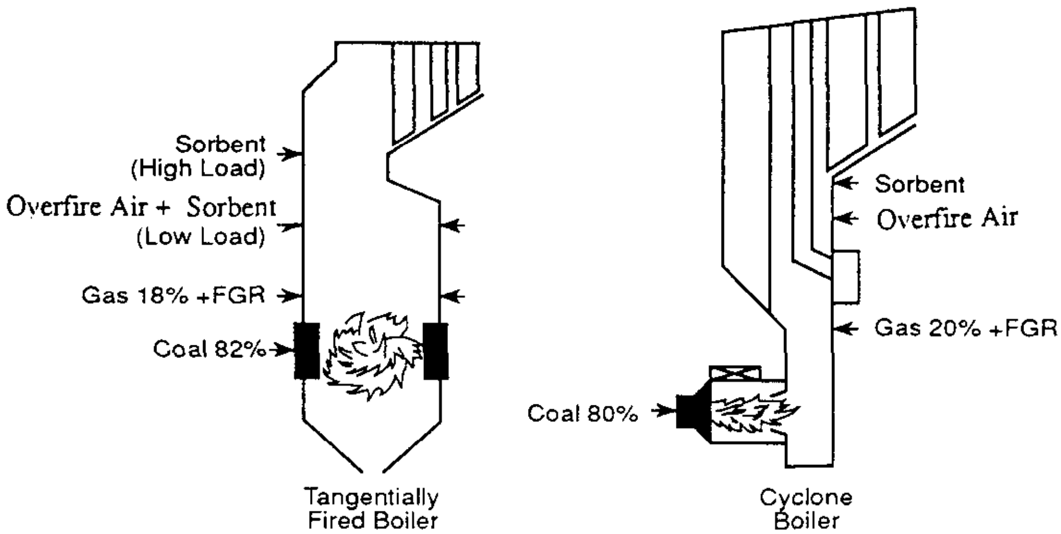


**Figure 4. Conceptual design for application of Gas Reburning to two host units.**

The tangentially fired unit has burners in each corner forming a large rotating fireball. With GR-SI, these burners will be turned down to 80 percent of full load with all burners in service. Natural gas, accounting for the other 20 percent of the total heat input, is injected through ports immediately above the upper row of burners. These ports are oriented co-tangential to the fireball. Flue gas recycle (FGR) is taken from the air preheater inlet and is added to the natural gas to achieve rapid gas mixing and penetration. The gas injectors are designed to tilt along with the coal burners. The overfire air (OFA) is also injected co-tangentially through four large ports. The injection velocity is relatively low to minimize furnace flow disruption.

At full load, the ideal temperature for sorbent injection occurs near the nose of the furnace; however, it moves lower in the furnace as load is decreased. To provide for sulfur dioxide control over the nominal unit load range, two sets of sorbent injectors are used. Ports along the front and side walls at the nose elevation will be used for full load operation. At low load, the sorbent will be injected along with the overfire air.

The cyclone-fired unit has two cyclones on the front wall discharging into a "well" type secondary furnace. There is intense mixing in this zone due to the cyclone swirl. Above the well, the furnace expands sharply producing a large recirculation zone with most of the flow passing up along the rear wall. With GR-SI, both cyclones will be turned down uniformly to 80 percent capacity. The reburning gas and FGR will be injected just above the well from the rear wall. The overfire air will also be injected from the rear wall further up in the furnace.

The ideal temperature for sorbent injection is at the entrance to the superheater in this unit. The flow patterns in this region are complex requiring a complex injector arrangement. A total of ten injectors will be used on the front and side walls.

The emission control performance of the GR-SI systems has been evaluated using EER's thermal, fluid flow, combustion, and sulfation models. Both configurations are projected to control $NO_x$ and $SO_2$ emissions to levels commensurate with the project goals of 60 percent $NO_x$ reduction and 50 percent $SO_2$ reduction.

## GR-SI FIELD EVALUATION RESULTS

### Hennepin GR-SI Results Overview

On-going tests at Illinois Power's Hennepin Generating Station Unit #1 have demonstrated that the Gas-Reburning Sorbent Injection (GR-SI) technology can achieve $NO_x$ and $SO_2$ reductions of 60 and 50 percent respectively. Testing has been conducted at the Hennepin plant since January 1991 and over 1500 hours of data have been logged through August, 1992 during the test phase of the project. Presently the testing program is in the long term test phase to demonstrate the effectiveness and operability of the process over a twelve month long period.

Preliminary analyses of the Hennepin test data indicate the following:

- Successful start-up and operation of the GR-SI system.
- $NO_x$ emissions have been reduced by up to 77 percent when compared to baseline levels while using 10-18 percent gas heat input.
- $SO_2$ emissions have been reduced by up to 62 percent with GR-SI and a sorbent injection rate with a Ca/S molar ratio of 2.
- Calcium utilization rates of 18-30 percent have been routinely achieved in short term tests.
- Data analysis indicates a close correlation with the predicted and pilot-scale results.
- No adverse effects on the boiler performance characteristics have been observed during the test phase of the project.

### Test Program

In order to customize the GR-SI system to Hennepin Unit #1, an intensive testing program was conducted to optimize the percentage of gas heat input, zone stoichiometries, gas injection velocity, sorbent mass flow rate, sorbent injection velocity and configuration, and boiler operational parameters. The goal of the test program was to identify those parameters which would enhance $NO_x$ and $SO_2$ reduction without detrimental effects to the boiler performance. A secondary goal of the Hennepin test program was to provide a data base which could be used to charachterize and retrofit other utility boilers.

In order to monitor the emissions and performance data, a Boiler Performance Monitoring System (BPMS) was installed at Hennepin Unit #1. Through the BPMS, EER personnel were able to continuously monitor emissions, heat absorption trends, stoichiometric calculations, boiler performance parameters as well as receiving up to the minute information on fuel mass flow rates, and steam rates, temperatures and pressures. In addition, manual sampling of particulate flow at the ESP inlet and out, $N_2O$ sampling at the stack breeching, and $H_2S$ sampling in the reburning zone were conducted, using EPA standard methods at appropriate test conditions and locations. Finally, in order to characterize the furnace flow field, in-furnace measurements of temperature and velocity were conducted before and after the installation of the GR-SI system.

**Gas Reburning Parametric Tests**

Figure 5 presents the results of the preliminary Gas Reburning tests performed during the first quarter of 1991. For these tests, the unit was operated near full load. Figure 5 compares $NO_x$ emissions for normal, staged air operation, and reburning conditions as a function of the overall excess air level (expressed as boiler exit stoichiometry). As indicated in this figure, application of gas reburning results in significant reductions in $NO_x$. For operation at 20 percent excess air, operating the unit with a minimal amount of overfire air results in reducing $NO_x$ emissions from approximately 460 ppm to 350 ppm. Application of gas reburning further reduces $NO_x$ emissions to below 200 ppm. One important factor to note is that retrofitting the Gas Reburning equipment to the unit has an impact on the baseline emissions from the boiler. Pre-modification $NO_x$ emissions were originally 550 ppm at a baseline excess air level of 25 percent.

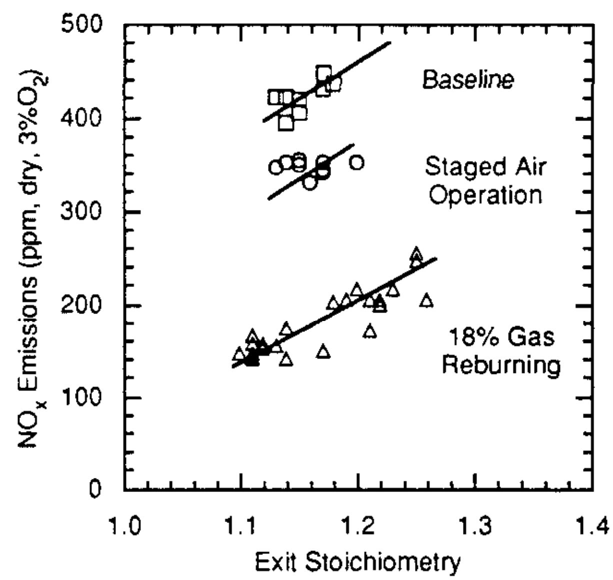


**Figure 5. Impact of Gas Reburning on $NO_x$ emissions at 70 $MW_e$.**

Figure 6 shows the preliminary Gas Reburning data compared to the uncontrolled baseline condition at a boiler load of 71 $MW_e$. The data was obtained by injecting varying amounts of reburning fuel while the overall excess air was maintained constant. The data with the highest reburning zone stoichiometry (115 to 125 percent theoretical air) is baseline data with no Gas Reburning. However, there is some staging due to the cooling air through the overfire air ports. Brief test with the cooling air shut off resulted in $NO_x$ emissions of 550 ppm. As the natural gas was increased, the reburn stoichiometry decreased toward the design point of 90 percent theoretical air and NOx emissions decrease to about 125 ppm. This corresponds to 77 percent reduction from the "as found" baseline. Figure 7 shows the $NO_x$ emissions as a function of load and stoichiometry of the reburning zone. By

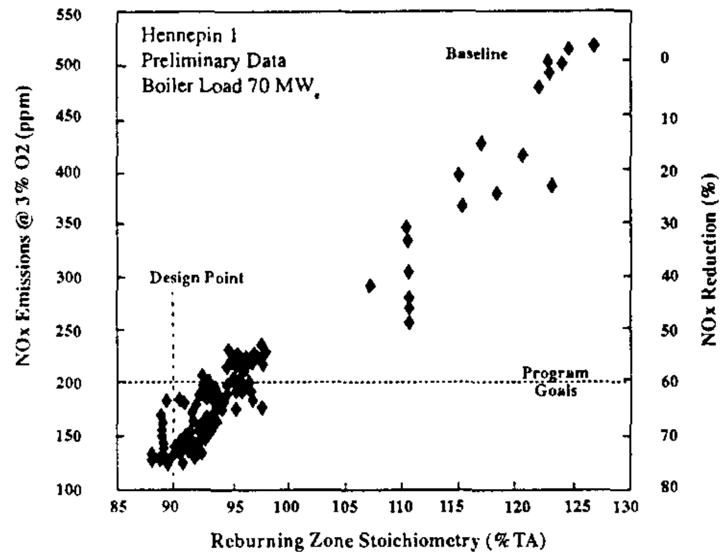


**Figure 6. Effective Reburning Zone Stoichiometry on $NO_x$ Emission**

increasing the natural gas injection rate, the reburning zone stoichiometry is decreased towards the design point of 0.9 resulting in greater $NO_x$ emissions reduction. Figure 7 shows that the efficiency of the reburning process is relatively independent of boiler load over a range of 60 to 70 $MW_e$. During the brief tests performed to date, no adverse performance impacts have been observed.

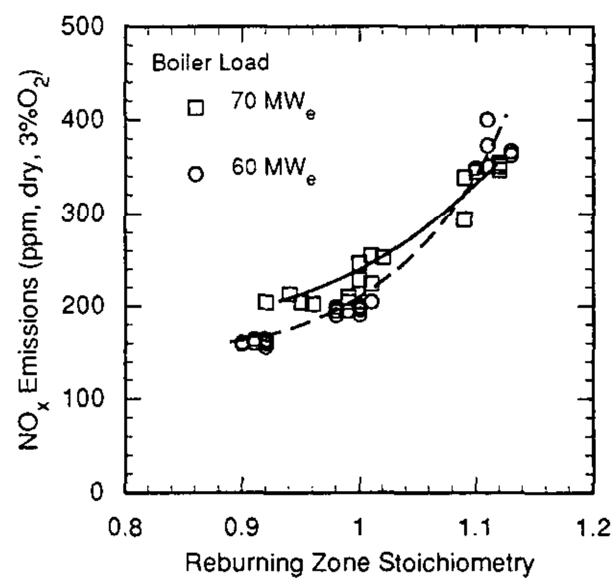


**Figure 7. Influence of Reburning Zone Stoichiometry on Reburning Effectiveness.**

## Sorbent Injection Parametric Tests

Sorbent injection tests show that $SO_2$ reduction of up to 62 percent have been achieved during the short-term tests. Figure 8 shows that the $SO_2$ emissions under the baseline conditions are 2600 ppm. The reduction was accomplished by reburning 18 percent natural gas and injecting the calcium based sorbent with a Ca/S molar ratio of 2, through the upper injection configuration at full load conditions. Current long-term tests show that the program goal of 50 percent $SO_2$ reduction can be achieved at a more moderate sorbent flow using a molar ratio of 1.75.

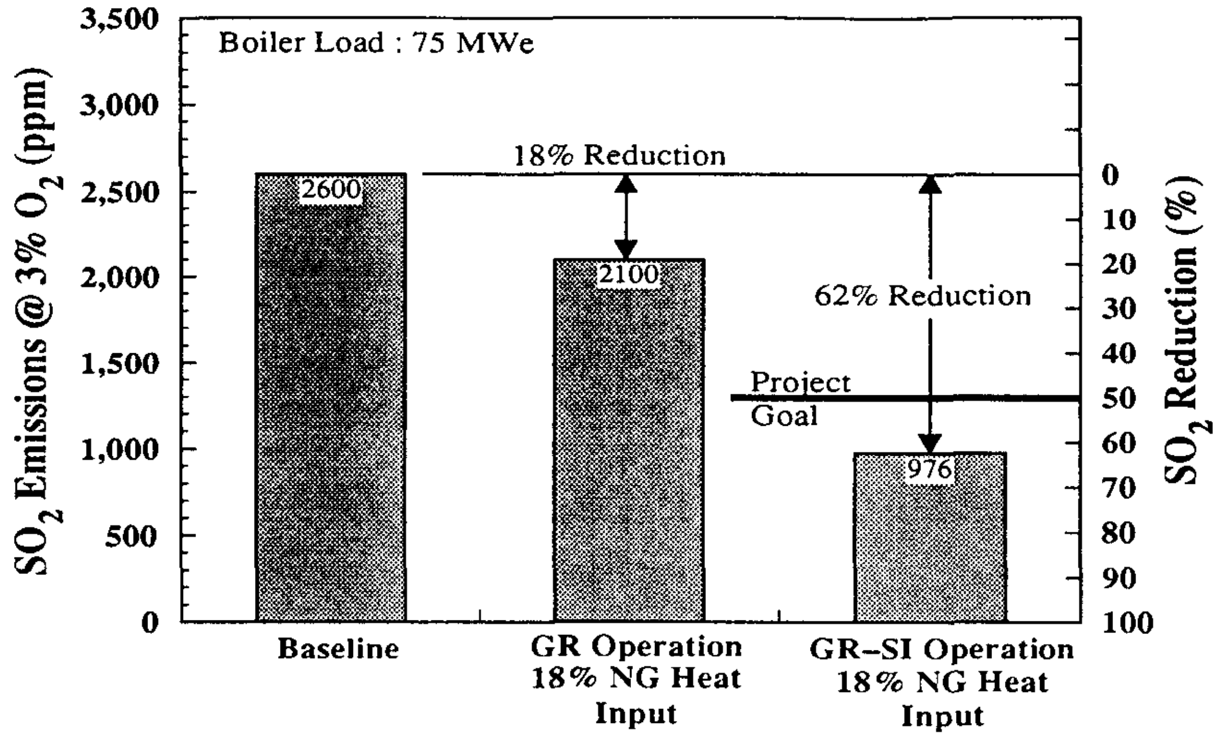


**Figure 8. GR-SI Baseline Performance Comparison**

Tests were conducted to examine the GR-SI system over a range of operating parameters and boiler loads to determine the optimum conditions for $SO_x$ and $NO_x$ emissions control. The results of these tests are shown in Figure 9 and indicate a peak, total sulfur removal of approximately 64 percent was achieved at a calcium to sulfur molar ratio of 1.83, corresponding to a calcium utilization of 30.4 percent. Figure 9 is based on the total sulfur dioxide removal which indicates the percent removal from the non-gas reburning baseline. In general, total sulfur removal ranged from 39.7 percent to 64.2 percent and calcium utilization ranged from 18.5 percent to 30.6 percent.

Figures 10 and 11 show sorbent sulfur removal for a wide range of loads. Sorbent sulfur removal is defined as the sulfur removal from the gas reburning baseline level. Sorbent sulfur removals ranged from 36.3 percent to 55.7 percent. The gas reburning system reduced sulfur levels by 16.1 percent to 19.2 percent from the non-reburning gas baseline during the GR-SI tests. Total sulfur removal does not equal the sum of these since the percent removal due to sorbent injection is computed from the lower gas-reburning baseline. Figure 10 compares EER's modeling results for the Hennepin Station with the actual operating data. As can be seen, there is good agreement between predicted results and the actual performance. Figure 11 compares Hennepin operating data with the range of past demonstrations results. As Figure 11 shows, the Hennepin results reside in the upper region of this operating envelope.

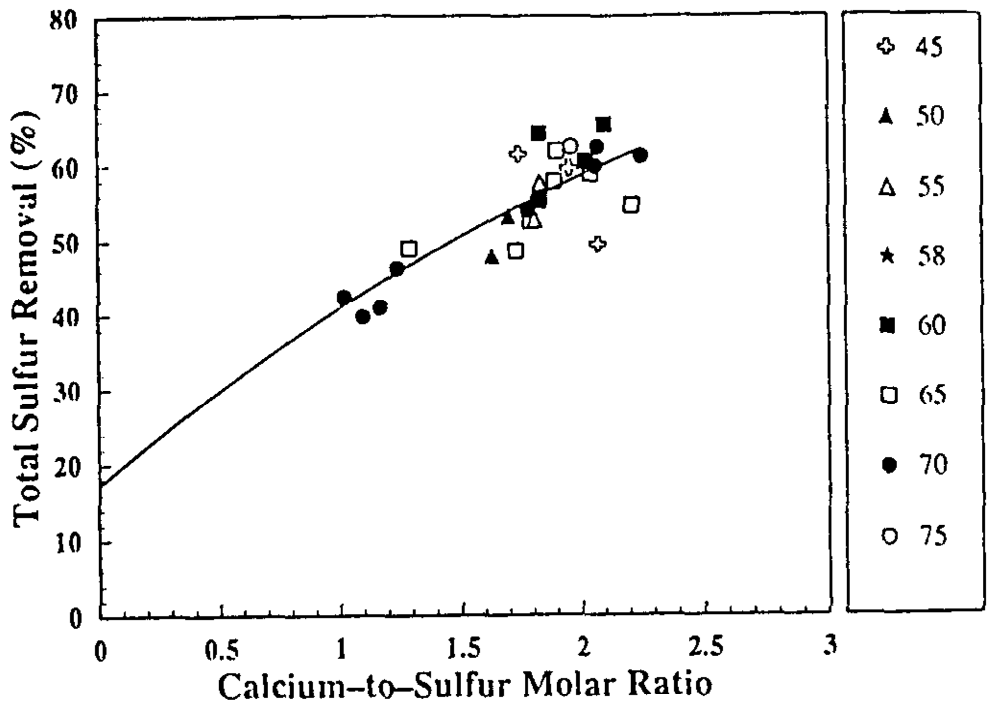


**Figure 9. Total Sulfur Removal During Parametric Testing at Hennepin**

## Impact on Boiler Performance Parameters

Boiler performance impacts at Hennepin Unit #1 are also being assessed. Ash deposition data and fireside corrosion data have shown no detrimental effect to the unit. To date, no indication of increased wall depositions have been encountered.

Heat absorption levels show that a slightly different trend exists with the GR-SI process. This is due to the increased particulate flow through the convective sections of the boiler. However, additional sootblowers were installed to maintain steam temperature at the design level. Gross heat rate and heat loss boiler efficiency are also maintained with only a moderate deviation. These results based on short term tests of GR-SI operation are shown in Figure 12. Work is continuing during current long-term testing to optimize operating conditions and sootblowing cycles.

## Long Term Testing

As stated previously, the objective of this demonstration is to determine the long term $NO_x$ and $SO_x$ emissions for a T-fired boiler retrofitted with GR-SI. Figure 13 shows load following capability of the GR-SI system at Hennepin Station for a typical day. As can be seen, $NO_x$ and $SO_x$ emissions remain relatively constant independent of unit load and meet current federal regulations. Figure 14 compares actual long-term operation over a two month period with the $NO_x$ and $SO_2$ program goals. With the exception of a few days during which sorbent quality was below specifications, long term operation of the GR-SI system has consistently met or exceeded the original program goals.

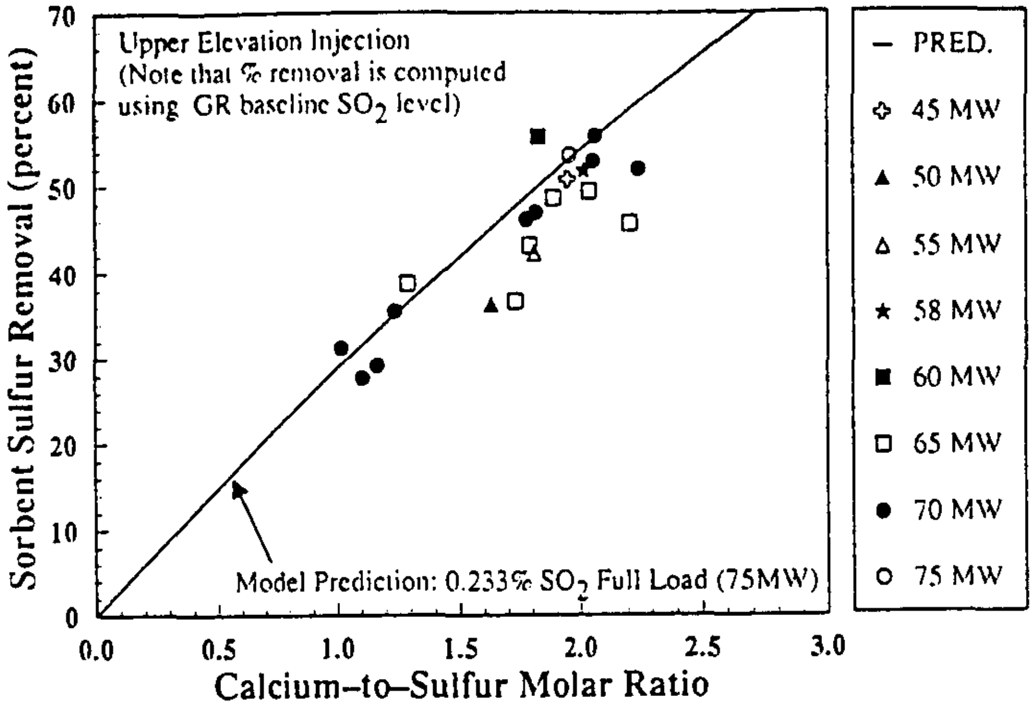


**Figure 10. Comparison of EER Modeling results for Hennepin Station with actual operating data**

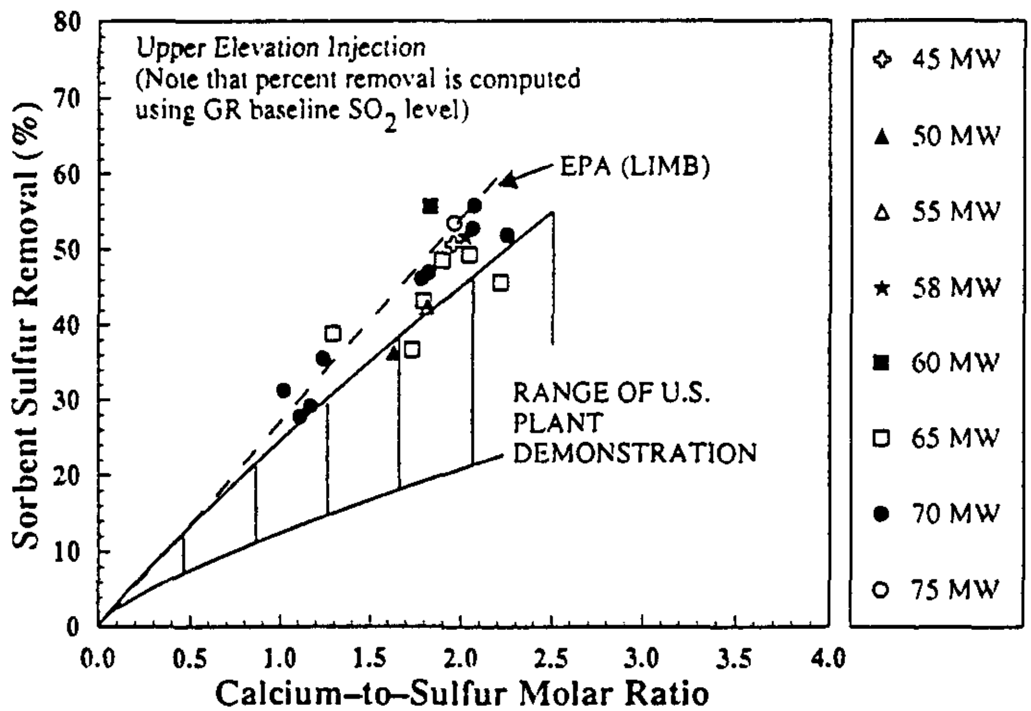


**Figure 11. Comparison of Hennepin Sorbent Injection Data with other demonstration results.**

## CONCLUSIONS

Gas Reburning is primarily a $NO_x$ emission control technology. Since it does not affect the design or operation of the combustion system, it may be integrated with a range of other emission control technologies for greater $NO_x$ and/or $SO_2$ control. Gas Reburning is being demonstrated on three coal-fired utility boilers as part of the DOE's Clean Coal Technology Program. Initial field test results on an 80 MW tangentially fired unit have shown that $NO_x$ and $SO_2$ reductions have exceeded the program goals of 60 and 50 percent reduction, respectively. This excellent performance has been achieved without adverse impact on boiler performance. Specific results achieved to date include:

- Successful start-up and operation of the GR-SI system;
- $NO_x$ emissions have been reduced routinely by 65-70 percent when compared to baseline levels while using 10-18 percent gas heat input;
- $SO_2$ emissions have been reduced routinely by 50-56 percent with GR-SI and a sorbent injection rate with Ca/S molar ratio of 1.75;
- Calcium utilization rates of 20-25 percent have been routinely achieved in long-term tests.
- Data analysis indicates a close correlation with the predicted and pilot-scale results;
- No adverse effects to the boiler performance characteristics have been observed during the test phase of the project.

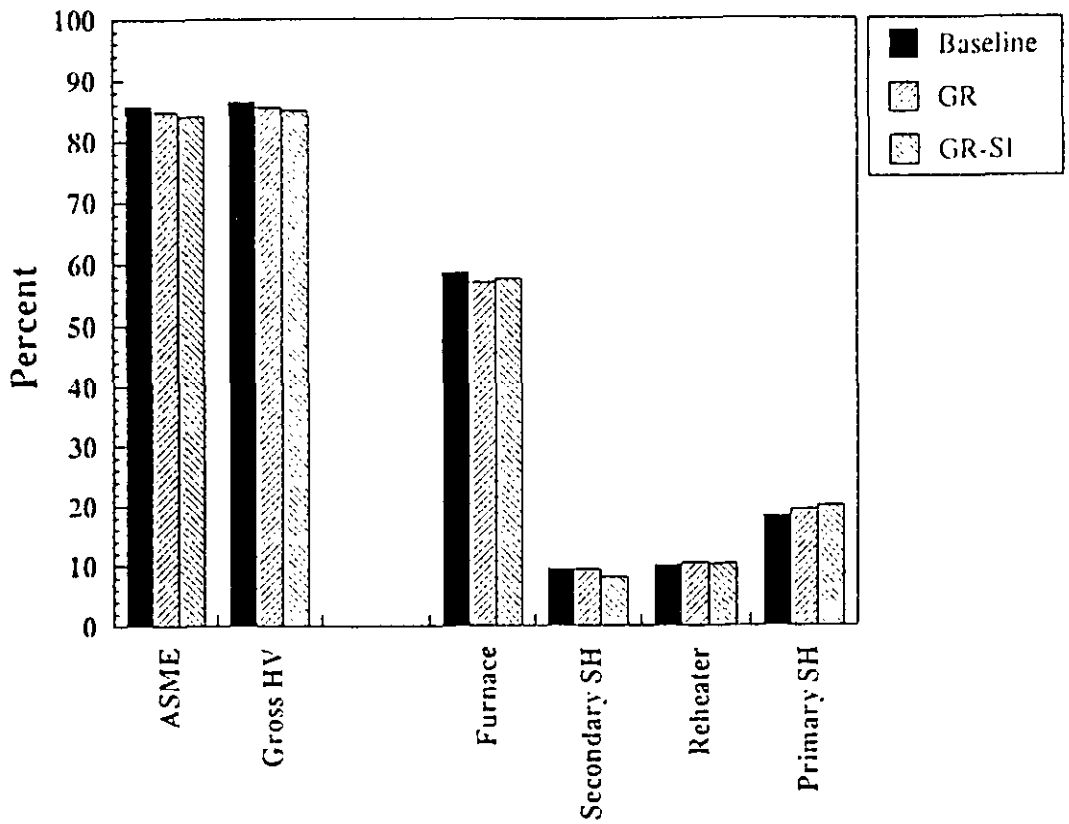


**Figure 12. Impact of GR-SI on Boiler Efficiency and Heat Absorption**

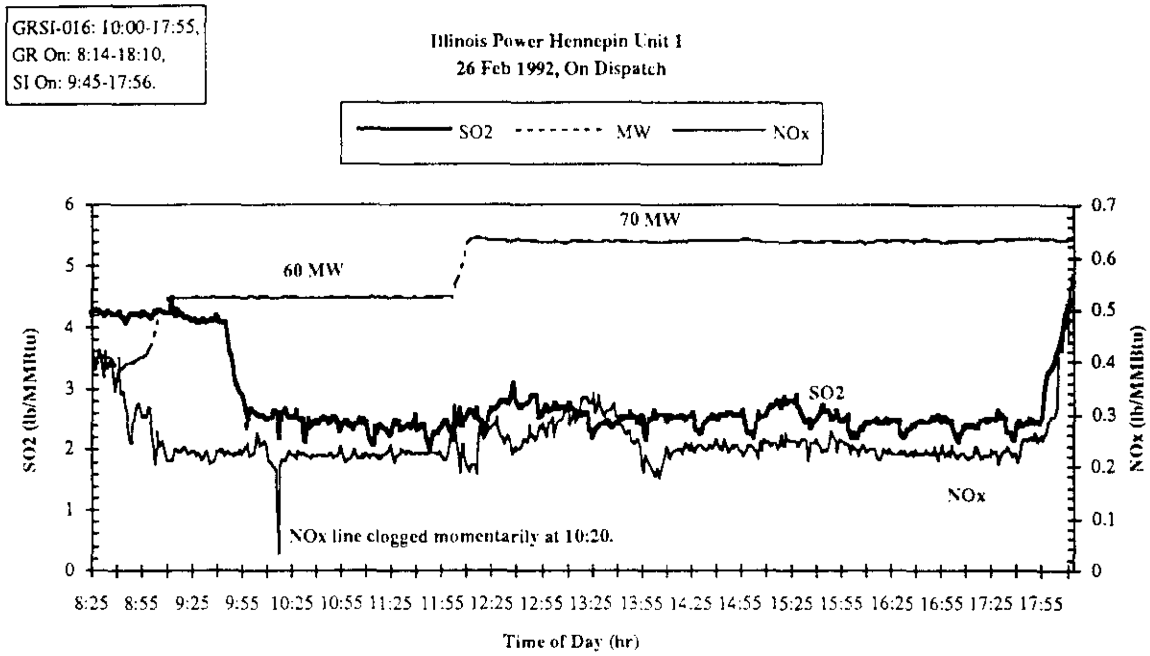


Figure 13. $NO_x$ and $SO_2$ Emissions under Load Following Conditions

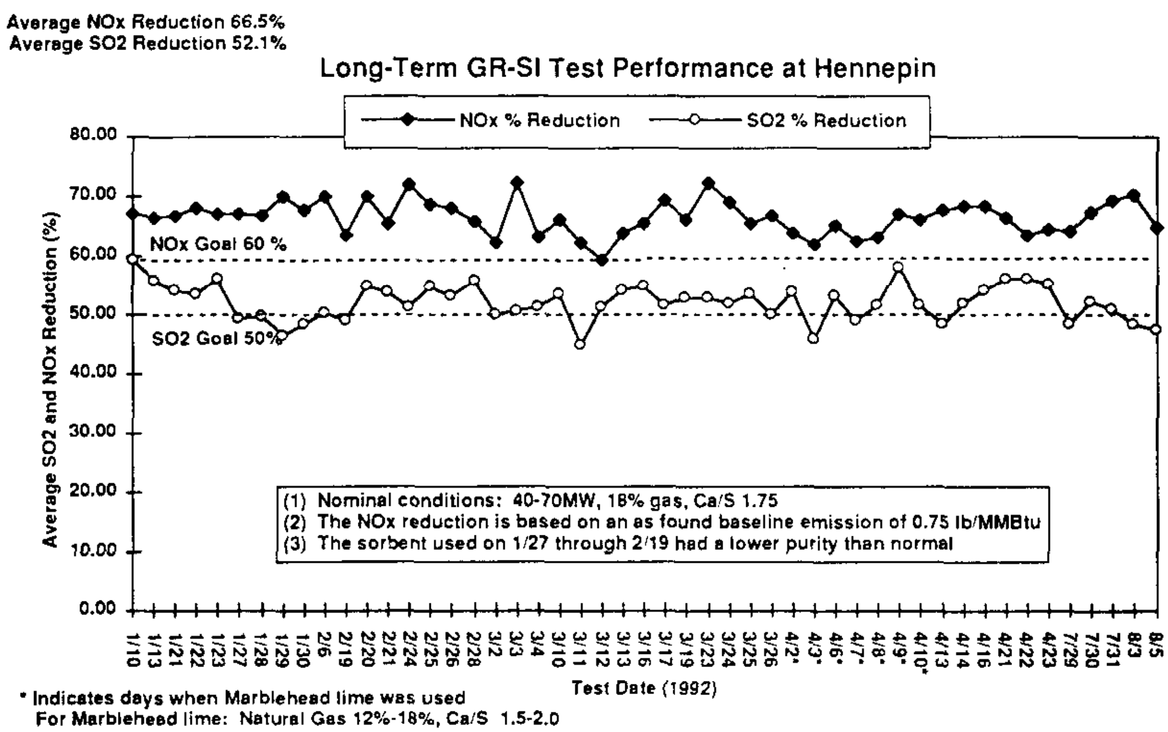


Figure 14. Long-Term Testing Trend Plots

## ACKNOWLEDGMENTS

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# Integrating Gas Reburning With Low NOx Burners

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## INTRODUCTION

The objective of this project is to demonstrate that the combination of gas reburning and low $NO_x$ burners installed on a wall-fired utility boiler will achieve 75 percent $NO_x$ reduction (Table 1). The project, conducted by Energy and Environmental Research Corporation (EER) is to design, install, and test the combined system.

Gas reburning involves cofiring 15 to 20 percent natural gas with coal. The gas is injected into the furnace above the main coal combustion zone to produce a slightly fuel-rich zone where $NO_x$ produced by the coal combustion is reburned and reduced to atmospheric nitrogen ($N_2$). Overfire air is added above this reburning zone to burn out the combustibles. Gas reburning alone can achieve about 60 percent $NO_x$ emission control. It also reduces $SO_2$, particulates and a $CO_2$, a greenhouse gas, by about 20, 20 and 8 percent, respectively, as a result of the fuel substitution.

**TABLE 1. GR-LNB PROJECT SUMMARY**

| | |
|---|---|
| **Technology** | Gas Reburning and Low NOx Burners |
| **Objective** | Demonstrate 75% NOx Reduction on a Wall-Fired Boiler at Public Service Company of Colorado |
| **Host Unit** | Cherokee Unit 3<br>172 MWe Front Wall Fired |
| **Scope of Work** | Turnkey - Design, Install, Test |
| **Schedule** | Start 10/13/90<br>Complete 6/12/94<br>Duration - 43 Months |
| **Funding** | Department of Energy<br>Gas Research Institute<br>Public Service Company of Colorado<br>Colorado Interstate Gas<br>Electric Power Research Institute<br>Energy and Environmental Research Corporation |

The host boiler for the project is Cherokee Station Unit 3 at Denver, Colorado. It is owned and operated by Public Service Company of Colorado (PSCO). The host unit fires Colorado bituminous coals and has a fabric filter dust collector. The low $NO_x$ burners are Foster Wheeler Internal Fuel Staging burners.

The 43 month, $14.3 million project is a Clean Coal Technology III program sponsored by the U.S. Department of Energy, Gas Research Institute, PSCO, Colorado Interstate Gas, Electric Power Research Institute, and EER.

## BOILER DESCRIPTION

Cherokee Station Unit 3 is a 172 MWe (gross) front wall-fired steam electric facility located in Adams County, Colorado (Table 2 and Figure 1). The boiler is a balanced draft pulverized coal unit supplied by Babcock & Wilcox. All four units at the station are typically on-line unless maintenance is being performed. As the demand load for the station rises, load on each of the four units increases proportionally. Individual units are loaded incrementally based upon current heat rates within a small operating range. At any one time, all four units are operating within 10 percent of each other with respect to percentage of capacity. The capacity factor and swing load conditions will allow evaluation of performance over a wide range of boiler operating conditions with minimal impact on normal plant operations.

### TABLE 2. PUBLIC SERVICE OF COLORADO CHEROKEE UNIT #3.

- Located in Adams County (Denver), Colorado
- Capacity: 172 MWe
- Type of Coal - Colorado Bituminous, 0.4% Sulfur (Yampa and Empire Mines)
- Start of Operation - 1962

- Particulate Emission Control - Baghouse
- Outdoor Installation
- Minimal Space Available and Limited Access
- Natural Gas Available

- Present Permit Conditions
  - Pre-NSPS
  - 0.1 lb/MMBtu Particulate
  - 20% Opacity
  - 1.2 lb/MMBtu SO2
  - No NOx Requirements

Low-sulfur coal is fed to four Riley Stoker No. 556 duplex drum type coal breaker and pulverizing mills, each having a maximum capacity of 37,000 pounds per hour. Coal fed to the mills is pulverized so that at least 70 percent will pass through a 200 mesh U.S.S. sieve (74 micron openings) and at least 98.5 percent will pass through a 50 mesh U.S.S. sieve (297 micron openings).

The pulverized coal is transported by a stream of 150°F air to a 4x4 array of Foster Wheeler Internal Fuel Staging low $NO_x$ burners, located on the front wall of the boiler. The radiant zone is 24 feet deep and 42 feet wide and has a full division wall. At the original full load, the design fuel heat input is 1.65 x $10^9$ Btu/hr.

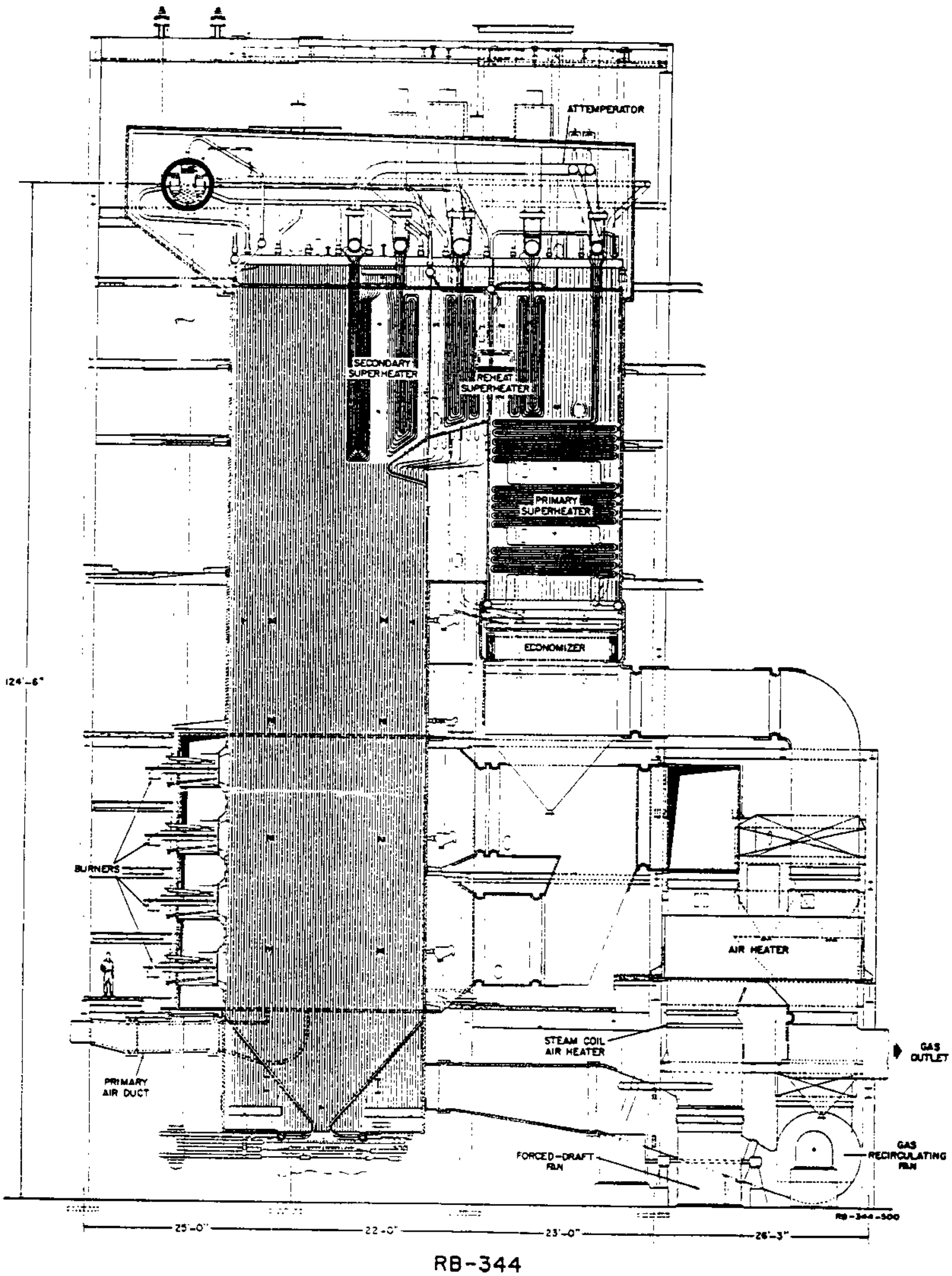


Figure 1. PSCO Cherokee Unit #3.

Baghouses are used to reduce particulate emissions control to less than 0.1 lb/MMBtu. Natural gas is available at the plant.

## TECHNOLOGY DEVELOPMENT

Gas reburning has been tested at large pilot scale and EER has developed a design methodology (Figure 2) to apply gas reburning to full-scale utility boilers. This design methodology was applied to three utility boilers of tangential, cyclone and wall firing configurations. In EER's Clean Coal Technology I projects, the tangential and cyclone applications are in the long-term field testing stage and the start-up stage, respectively. Another EER paper will discuss these two applications, which have provided a validation of the design methodology and $NO_x$ control effectiveness. The Cherokee project discussed here is a CCT III project and will provide the needed wall-fired gas reburning demonstration and design methodology validation.

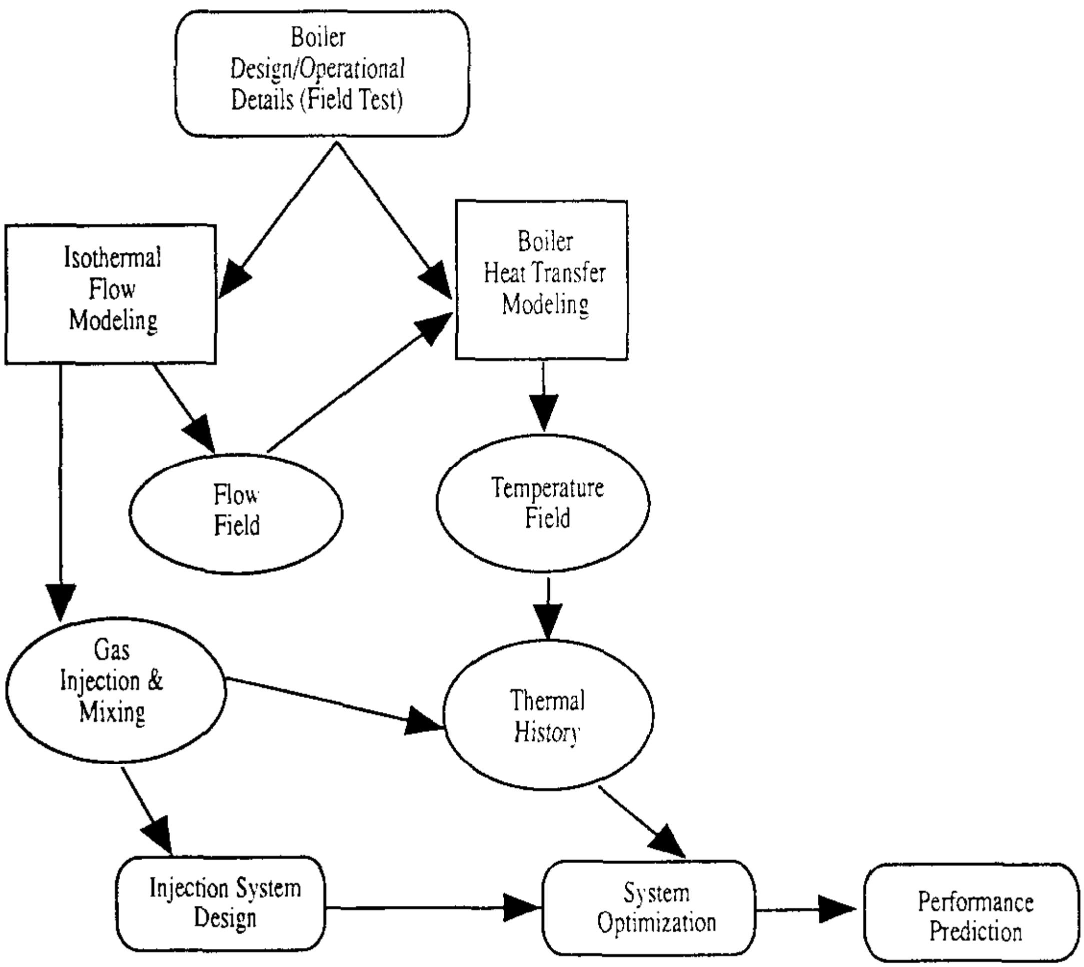


Figure 2. Gas reburning - boiler application - design methodology.

Low $NO_x$ burners for wall-fired boilers are commercial at present and provide very cost-effective $NO_x$ emission control. However, the $NO_x$ control achieved is limited to 30 to 50 percent. They have never been integrated with gas reburning. This project will provide such an integration.

Briefly, the EER's design methodology involves the application of various experimental and analytical tools to adapt the reburning process requirements to the specific boiler geometry and operating parameters. For Cherokee Unit 3, the isothermal model and the dispersion patterns are shown in Figures 3 and 4, respectively.

The combined technology is easily retrofitted to wall fired boilers at low capital cost.

## GR-LNB TECHNOLOGY

The gas reburning (GR) - low $NO_x$ burners (LNB) system is shown in Figure 5.

**Low $NO_x$ Burners.** Sixteen Foster Wheeler Internal Fuel Staging low $NO_x$ burners (Figure 6) were installed in place of Babcock & Wilcox circular type PL burners. The low $NO_x$ burners employ dual combustion air registers which allow for control of air distribution at the burner, providing independent control of the ignition zone and flame shaping. For the application at Cherokee Unit 3, Foster Wheeler will produce a nominal 40 percent reduction in $NO_x$ at 150 MWe relative to the nominal baseline emission. Actual $NO_x$ reduction for the burners will be determined during optimization studies prior to the long-term testing.

**Gas Reburning System.** Based on EER's design, the natural gas reburning fuel together with flue gas recirculation (FGR) is injected through sixteen 5.5 inch diameter front and rear wall nozzles. Eight nozzles are located on each of the front and rear walls of the furnace. This configuration provides for adequate wall to wall and lateral coverage. The nozzle exit velocity varies linearly with boiler load, ranging from about 90 ft/sec at 50 percent load to over 180 ft/sec at 100 percent load. At full load, the required velocity head for the composite nozzle is 3.83 inches of water column. The range of design flow rates of natural gas is 10 to 25 percent of the boiler's total fuel input. Approximately 3.4 percent of the flue gas is injected through the gas reburning nozzles to improve mixing of natural gas and coverage within the furnace.

Overfire air is injected into the furnace through six 20.5 inch diameter injectors located on the front wall of the furnace. The injectors are tilted downward 10 degrees to improve overfire air coverage and to increase residence time. The operator first starts the overfire air booster fans. Then the overfire air flow increases until the desired burner zone stoichiometry is achieved. After selecting a reburning zone stoichiometry, natural gas flow is manually initiated and then switched to automatic control of gas reburning. To shut down GR-LNB, the operator reverses these steps. While the system is being shut down, cooling air flows through all GR-LNB nozzles.

## GR SYSTEM COMPONENTS

The GR system comprises three integrated systems: (1) natural gas injection, (2) flue gas recirculation, and (3) overfire air system.

Natural gas is injected into the furnace above the burner zone to induce substoichiometric conditions to form several species of free hydrocarbon radicals that react with $NO_x$ formed in the burner

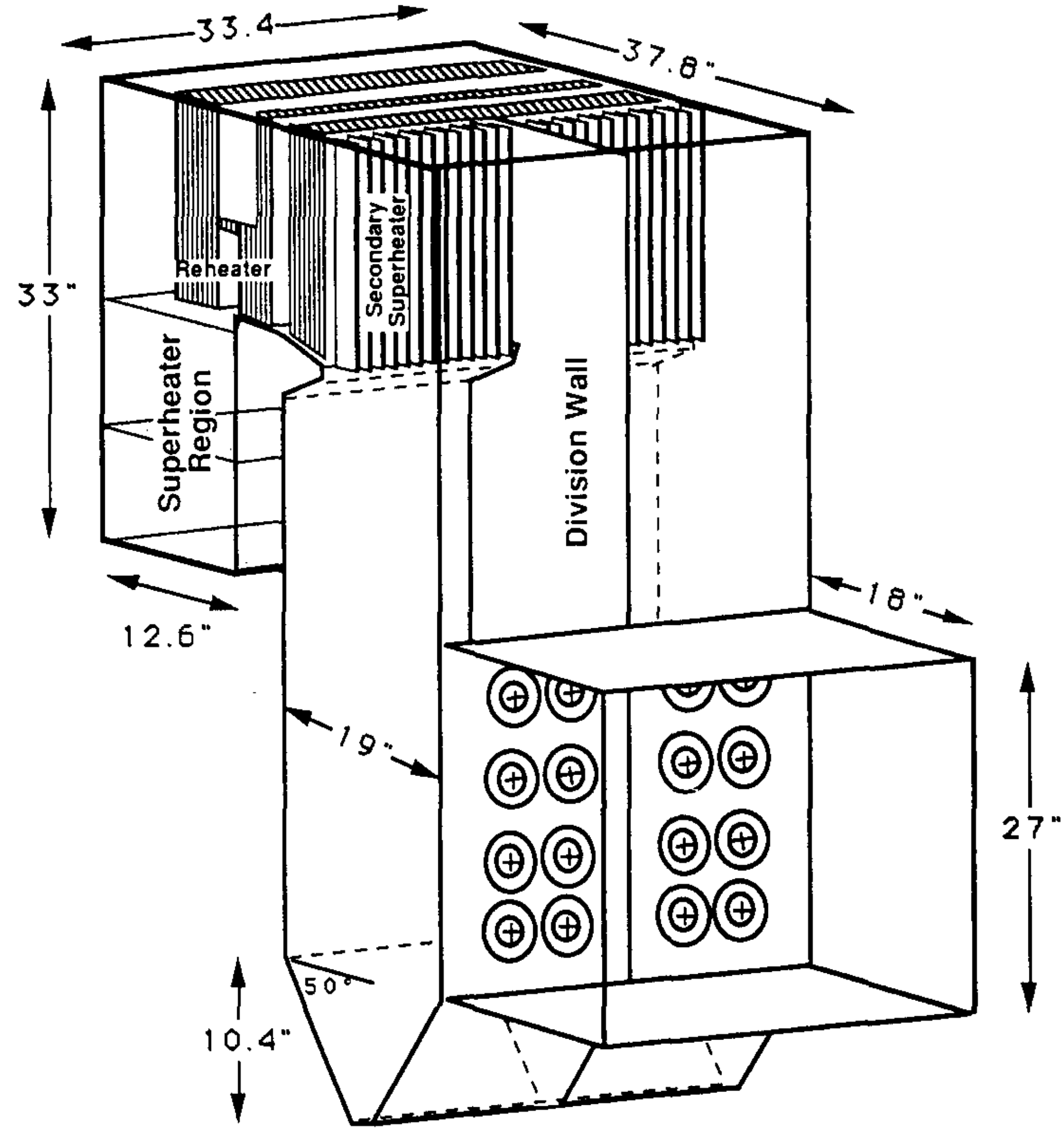


Figure 3. Isothermal model of Cherokee Unit 3.

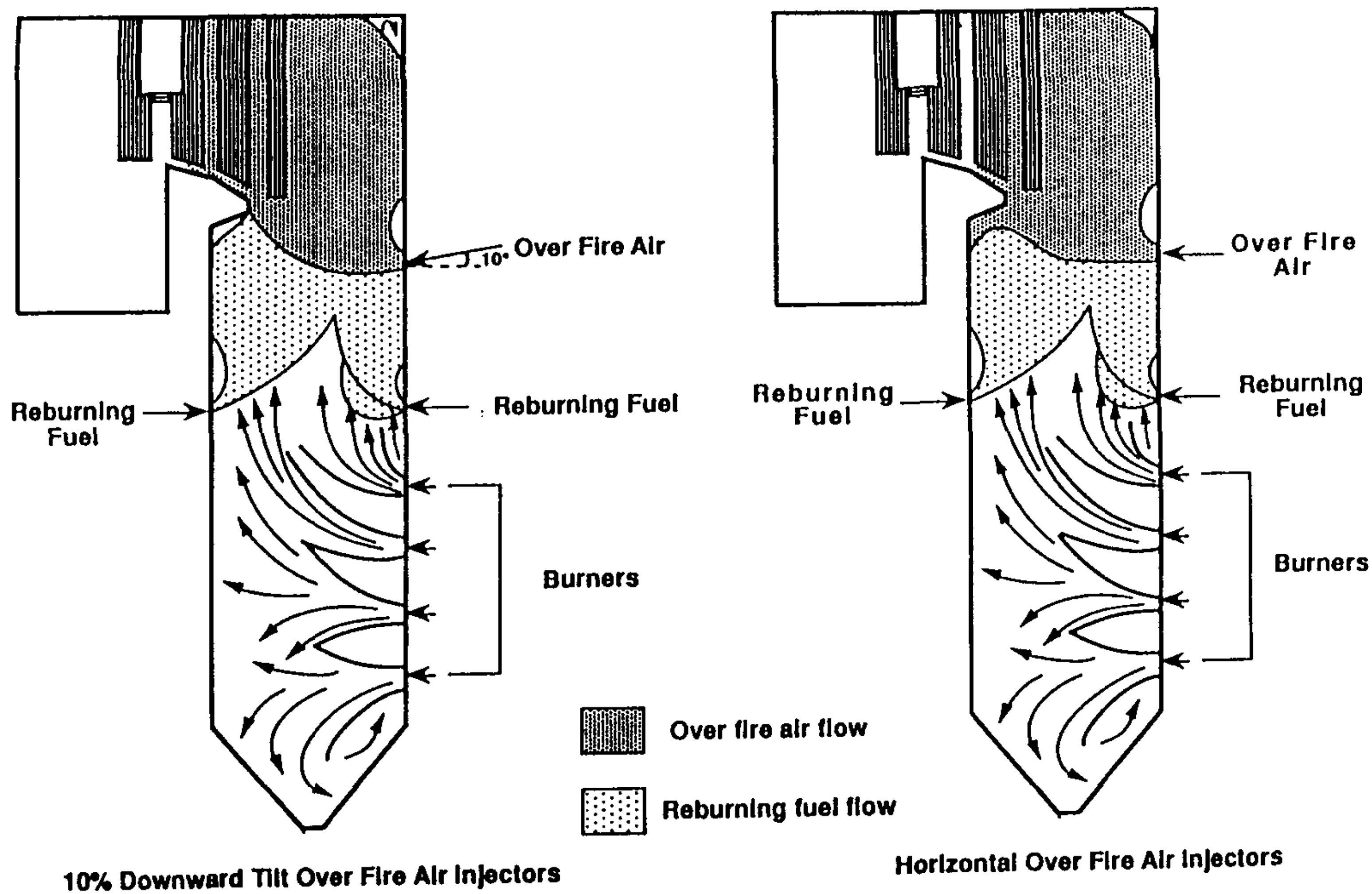


Figure 4. Dispersion pattern for Cherokee Unit 3 Gas Reburning.

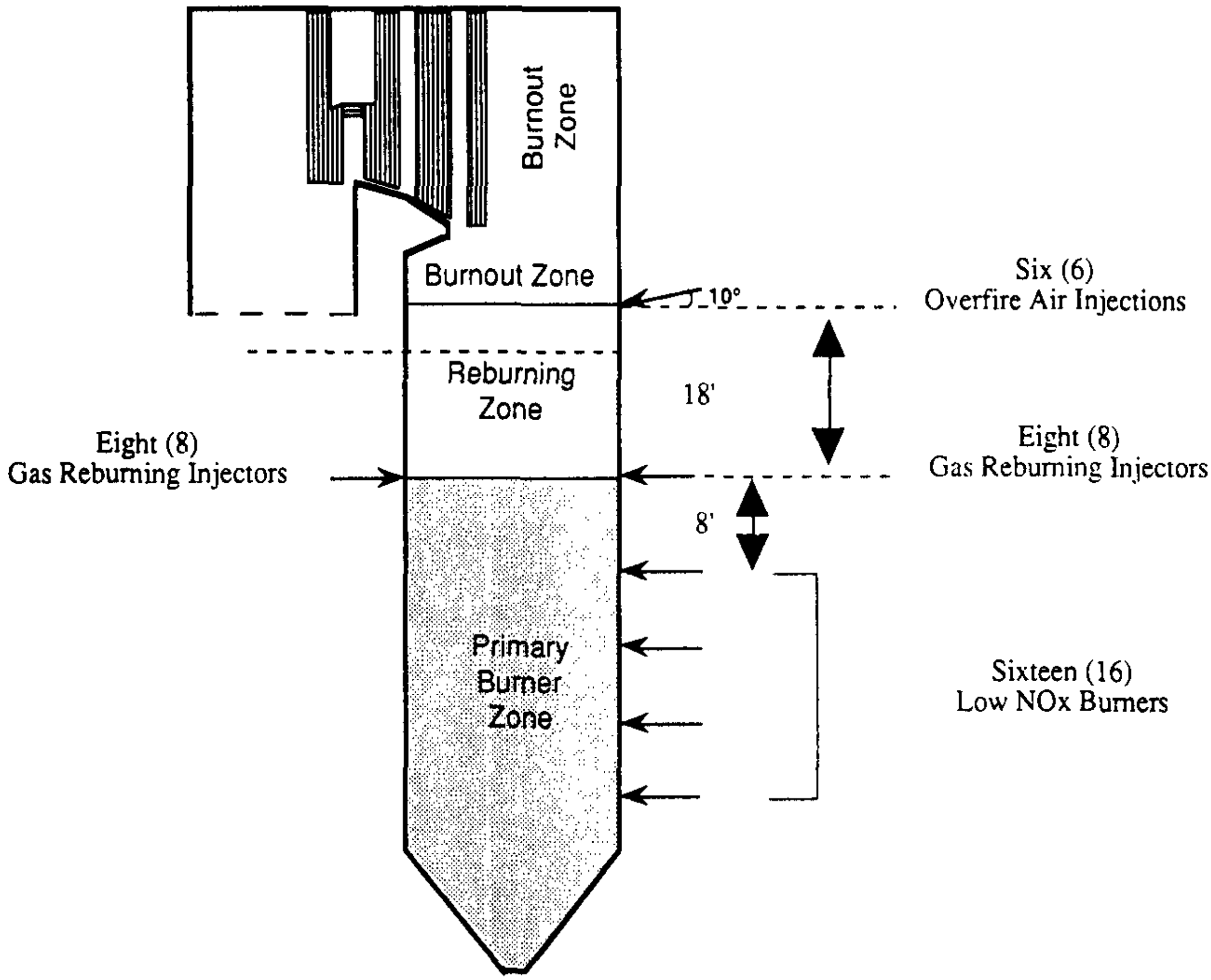


Figure 5. GR-LNB System.

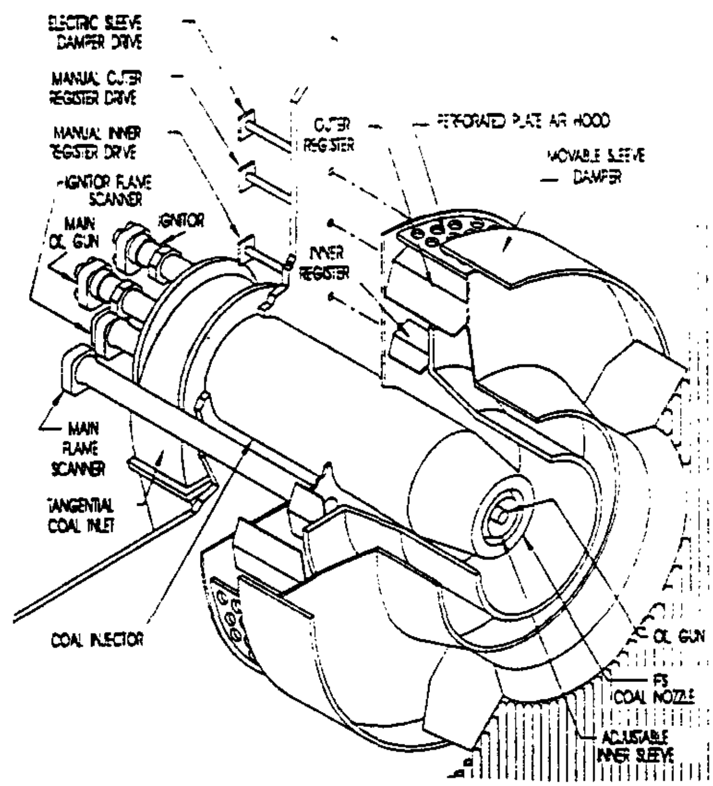


**Figure 6. Internal fuel staging burner.**

zone. Overfire air is then added at a higher furnace elevation to complete the combustion process at lower furnace temperatures, thereby reducing thermal $NO_x$ formation. The volume of gas injected, while accounting for roughly 20 percent of the full heat input, represents less than 2 percent of the mass flow through the reburning zone. To obtain furnace penetration and good mixing, the mass flow of the injected gas must be increased with an inert gas. Recirculated flue gas is used as the most logical source.

**Natural Gas Injection**. The naturals gas system (Figure 7) is designed for a maximum gas flow of 7500 scfm. Gas is taken from the Unit 3 supply line prior to the final pressure reducing valve and flow control valve. A supply line transports the gas to the reburn gas metering and control station near the reburning zone elevation. Downstream of a manual isolation valve the volume of gas used is totalized through a rotary meter and then the gas pressure is reduced to 20 psig. Local pressure indicators are provided upstream and downstream of the pressure reducing valve. High and low pressure mercury pressure switches are installed downstream of this valve as protection against unsafe fluctuations in the gas supply.

The flow metering and control station consists of orifice plates for determining flow rates and a V-notch ball control valve with a pneumatic positioner. The natural gas safety station consists of a pressure safety vent piped to above the boiler, and a standard double block and bleed arrangement of block valves. The double block and bleed valves will be tripped by any number of safety interlocks to guard against unsafe operating conditions.

From the control station, the gas flows to a header parallel to the rear furnace wall at the injection elevation. Each injection nozzle is fed from the header through an isolation valve and a flow balancing valve with a local pressure gauge.

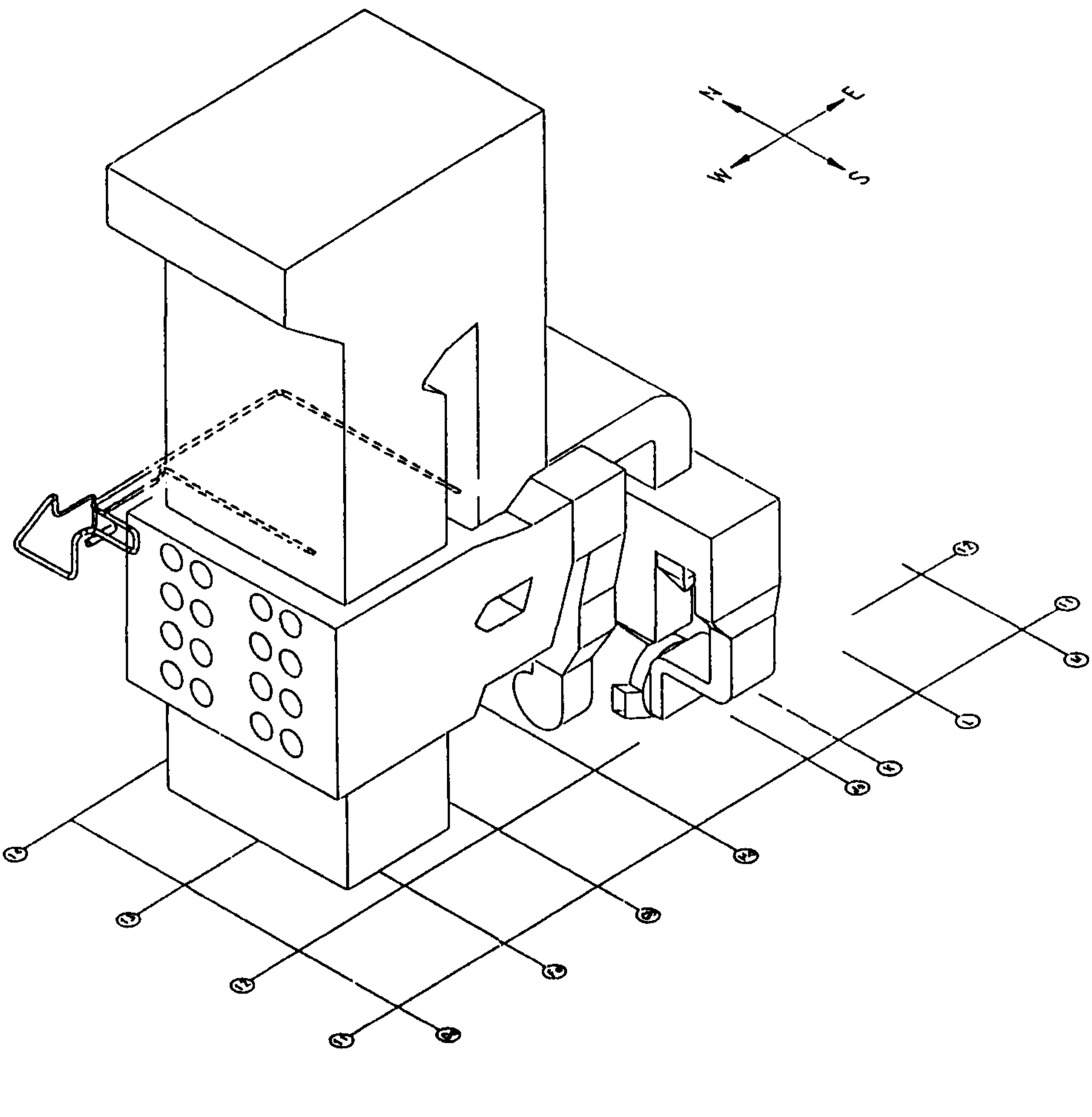


Figure 7. Natural Gas System.

Two key safety features are used for the gas injection system flame scanners and optical pyrometers. Flame scanners are used on older units such as Cherokee Unit 3 with the original control still functioning (pneumatic with no flame safety system). The scanners are used to prove a main flame condition in the burner zone prior to and during gas injection. Optical pyrometers are used to prove furnace temperatures above 2,000°F to ensure instantaneous ignition of the injected gas.

**Flue Gas Recirculation**. To improve gas penetration and furnace mixing, recirculated flue gas is used to increase the mass flow of the injected gas. As shown in Figure 8, flue gas is recirculated from the exit of the economizer at a temperature of approximately 725°F. Flue gas is taken from each side of the unit to maintain a balanced flow through the back pass convection sections. Cherokee Unit 3 was designed and still operates with flue gas recirculation (FGR) for steam temperature control. Flue gas is recirculated through two FGR fans with a combined capacity of 140,000 cfm or roughly 20 percent of the flue gas flow. The recirculated flue gas is taken just upstream of the air heaters and partially cleaned in a multiclone particulate collector. The FGR fans discharge the flue gas into the bottom of the furnace below the burner zone. The one new FGR fan for gas reburning only recirculates 3 percent of the total flue gas flow, but discharges at a much higher static pressure to achieve the high velocity head required for injection. The gas reburning recirculated flue gas is controlled by parallel blade dampers on each fan inlet equipped with electric positioners. Flow is controlled as a function of boiler load to maintain the optimum injection velocity for the given furnace mass flow. The FGR flow is measured by use of two venturis incorporated into the FGR ductwork on each side of the unit. Each fan supplies half of the injection nozzles on the rear furnace wall. Manual butterfly dampers and pressure indicators are included for each injection port. The flue gas is injected through the outer annulus of the coaxial design nozzle. To keep the gas reburning nozzles cool during non-gas reburning operating periods, small cooling fans supply air to each FGR duct.

**Overfire Air.** To complete the combustion process,s additional combustion air s added as ovefire air. As shown in Figure 9, the optimum injection elevation or overfire air is on the front wall of the furnace approximately two-thirds of the distance between the top burner elevation and the nose of the arch extending from the rear wall below the entry into the superheater. The source of overfire air is the secondary air ducts on either side of the unit. The overfire air is taken prior to the split in the secondary air duct so as not to bias the remaining flow to the windbox. The pressure in the windbox at full boiler load is roughly 2-1/2 to 2-3/4" $H_2O$. This static pressure is too low to achieve adequate velocity head for injection of the overfire air. For this reason, two ovefire air (OFA) fans are used to boost the static pressure to 10" $H_2O$ for injection. The OFA fans are sized to supply 25 percent of the total air flow from the FD fans, but only splits the normal air flow between the primary combustion zone and upper furnace burnout zone. Control of the OFA consists of the existing control system setting demand signal based upon coal flow and boiler $O_2$ and splitting the corresponding flow to obtain a stoichiometry of 1.1 in the burner zone with the balance of the air being injected as OFA. OFA flow is metered by using an averaging Pitot grid measurement device in each OFA duct. The OFA flow is controlled by parallel blade dampers on each OFA fan inlet. Each fan supplies half of the OFA ports on the upper furnace front wall.

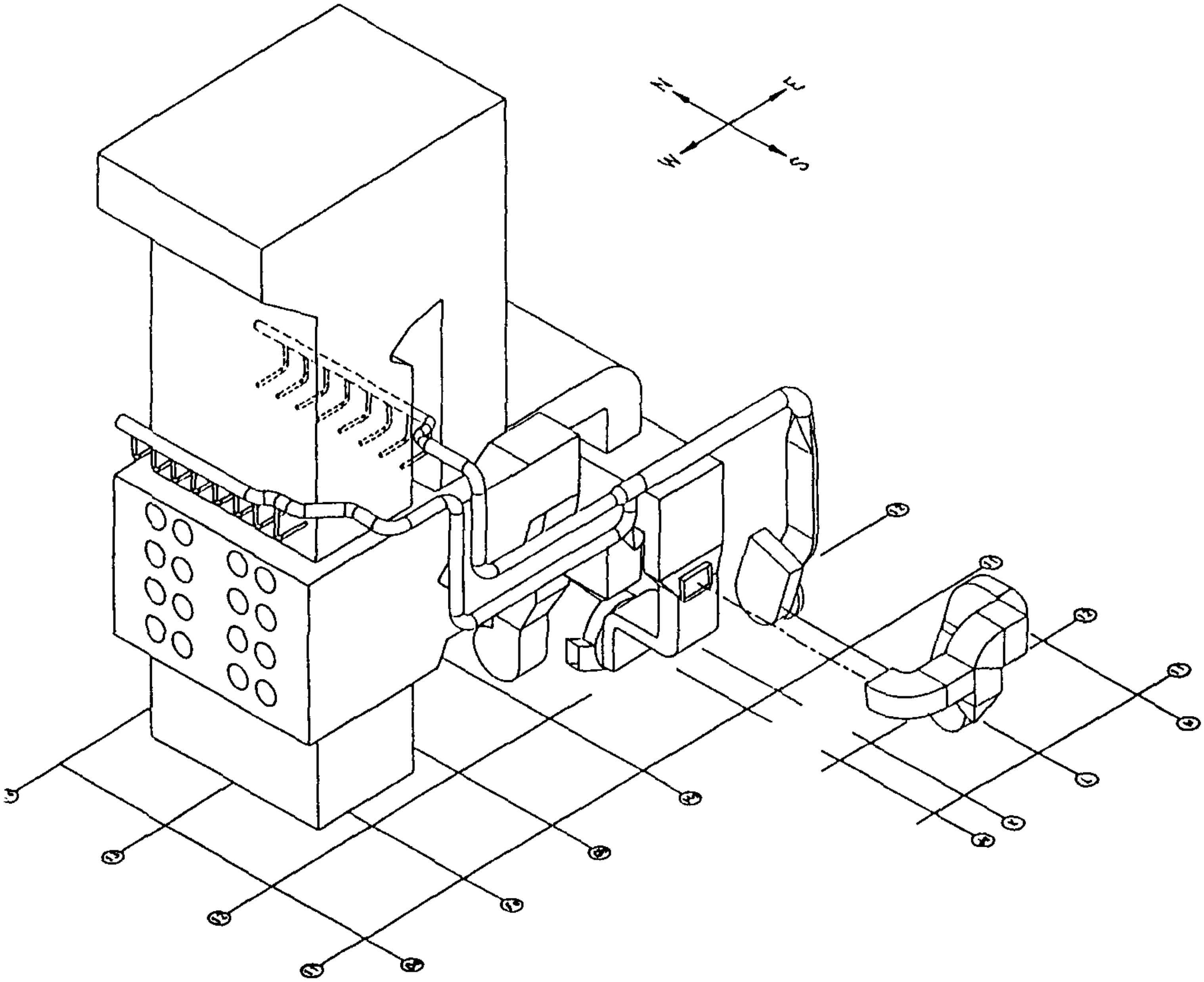


Figure 8. Flue Gas Recirculation System.

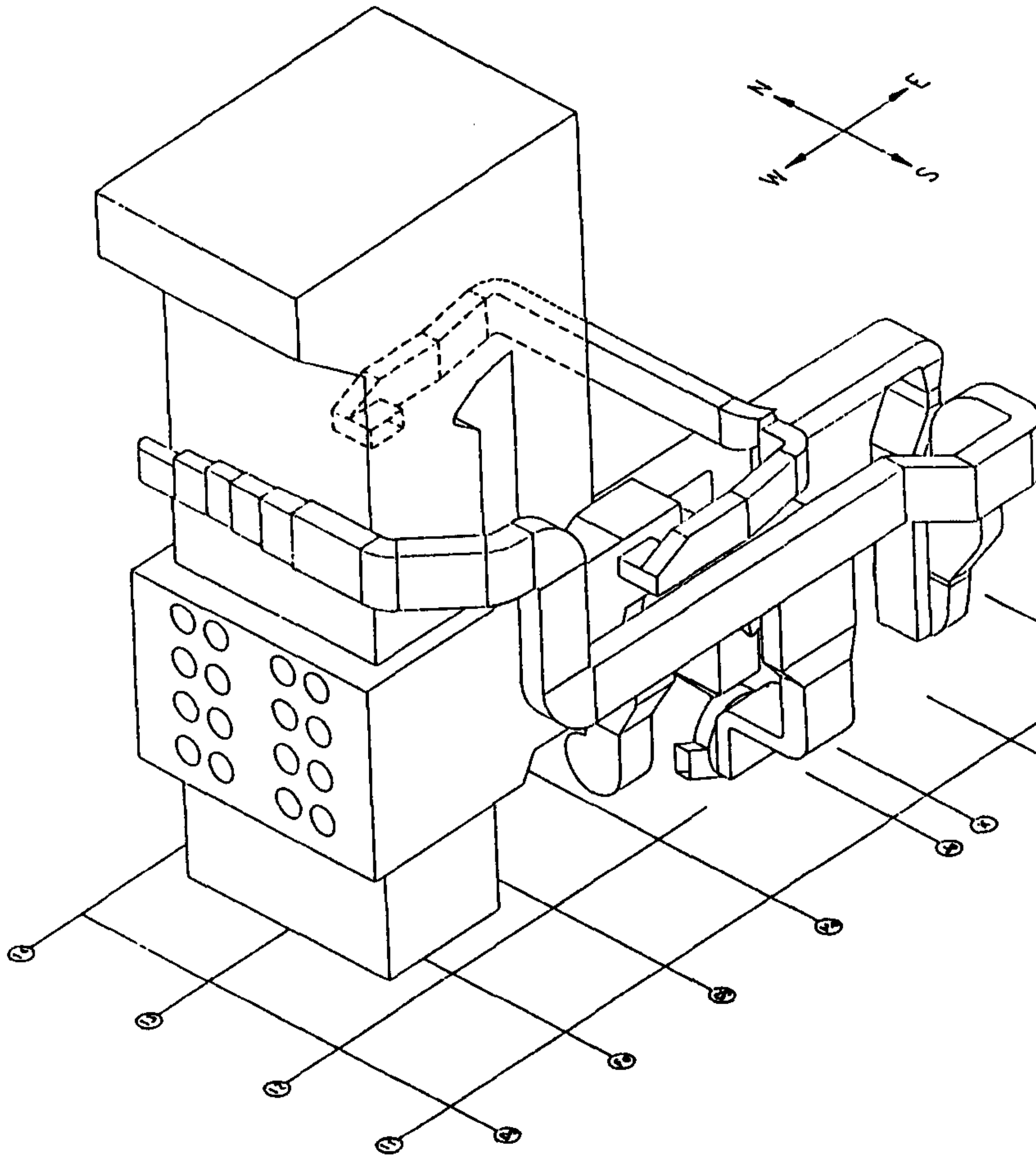

Figure 9. Ovefire Air System.

## PROJECT SCHEDULE

The project is being conducted in three phases:

Phase I - Design and Permitting;
Phase II - Construction and Start-Up
Phase III - Operation, Data Collection, Reporting and Disposition.

The program is now in Phase III. The Phase III schedule is shown in Figure 10. The optimization testing (for GR and LNB-GR) will be conducted for a period of 3 1/2 months from mid-September to the end of December, 1992. The long-term testing will be carried out from January to December, 1993.

## TEST PLAN

Process variables to be studied include:

Loads: 60 to 150 MWe
Mills in service: 4 or 3
Gas heat inputs: 0 to 25 percent
Flue gas recirculation: cooling to 3.4 percent
Ovefire air flow: cooling to 75,000 scfm
Coal zone stoichiometries: 1.05 to 1.26
Reburn zone stoichiometries: 0.88 to 1.16
Exit zone stoichiometries: 1.16 to 1.33

Measurement to be conducted include:
Continuous flue gas analysis for $SO_2$, $NO_x$, $O_2$, $CO_2$, CO and total hydrocarbons
Boiler exit temperature, CO and $O_2$ patterns
Unburned carbon in flyash at the air heater exit
Ultrasonic boiler tube thickness inspection

Before the installation of the GR-LNB system, the boiler was tested in the "as-found" condition. The only parameters that were varied during the baseline testing were excess $O_2$ and load.

| | % $O_2$ | |
|---|---|---|
| MW | Low | High |
| 150 | 2.88 | 6.04 |
| 120 | 3.30 | 5.69 |
| 90 | 3.95 | 6.58 |
| 60 | 3.75 | 6.27 |

The boiler baseline emissions at 150 MW (net) load for dry, 3 percent $O_2$ basis are as follows:

$NO_x$ = 541 ppm = 0.73 lb $NO_x$/MMBtu
$SO_2$ = 355 ppm
$CO_2$ = 67 ppm
CO = 17.28 percent

Unburned carbon in flyash = 4.44 percent (at air heater outlet)

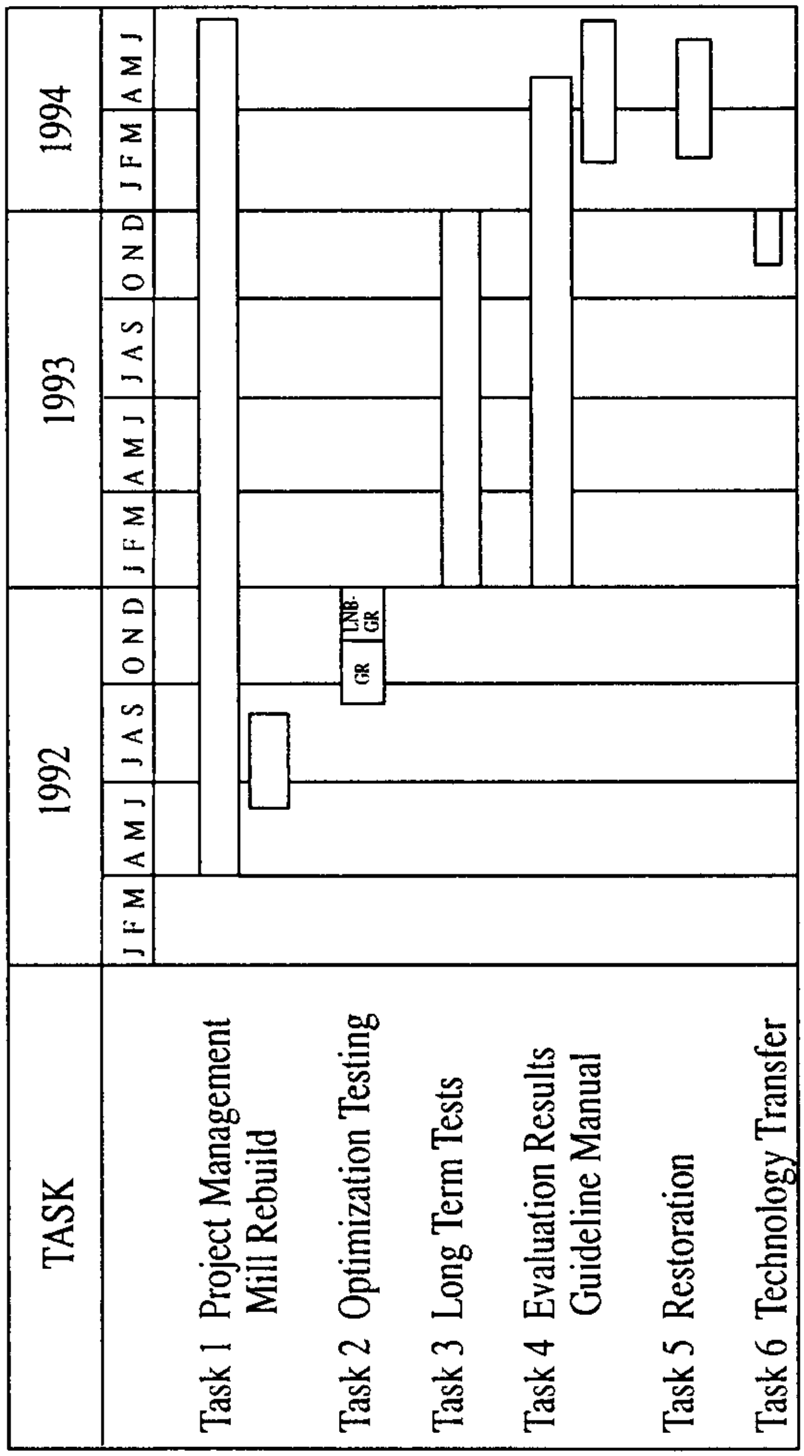


Figure 10. GR-LNB phase III schedule.

Based on these data, the gas emissions reduction goals of the GR-LNB system are shown in Table 3. These goals are based on 40 percent $NO_x$ reduction by LNB only and 75 percent $NO_x$ reduction by GR-LNB using 20 percent natural gas heat input. In addition to the gas emissions reduction, flyash to landfill is expected to decrease by 20 percent, and baghouse outlet particulate loading to decrease up to 20 percent as a result of fuel switching.

## MARKET POTENTIAL

The Clean Air Act Amendments of 1990 require $NO_x$ emission reductions through the use of low $NO_x$ burner technology. By January 1, 1995, the maximum allowables $NO_x$ emissions for tangentially and wall-fired boilers are set at 0.45 and 0.50 lb/MMBtu, respectively.

The combined GR-LNB technology will achieve a much higher $NO_x$ emissions reduction than the LNB technology alone. In addition, $SO_2$ emissions and flyash to landfill will decrease by a percentage corresponding to gas heat input. $CO_2$ emissions will also decrease.

If the GR-LNB technology can achieve its $NO_x$ reduction goal of 75 percent, its performance will be fairly comparable with that of the Selective Catalytic Reduction (SCR) technology. The GR-LNB technology is expected to have lower capital and operating costs than the SCR technology which uses ammonia as a $NO_x$ reducing agent over a catalyst bed.

There have been some inquiries about the GR-LNB technology. EER will be ready for the commercialization of this technology when optimized field test results are available by the end of the year.

TABLE 3. GAS EMISSIONS REDUCTION GOALS

Full Load

| | Baseline | LNB Only | GR-LNB |
|---|---|---|---|
| NOx (ppm) | 541 | 325 | 135 |
| NOx (lb/MMBtu) | 0.73 | 0.44 | 0.18 |
| SO2 (ppm) | 355 | 355 | 285 |
| CO2 (%) | 17.3 | 17.3 | 15.9 |

# Micronized Coal Reburning for NOx Control on a 175 MWe Unit

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## ABSTRACT

*The Tennessee Valley Authority (TVA) along with MicroFuel Corporation, Research-Cottrell Research & Development, and Duke/Fluor Daniel have been selected for the Department of Energy's (DOE's) Clean Coal Technology IV program to demonstrate Micronized Coal Reburn technology for control of nitrogen oxide (NOx) emissions on a 175 MWe wall-fired steam generator at its Shawnee Fossil Plant. This retrofit demonstration is expected to decrease NOx emissions by 50 to 60 percent. Up to 30 percent of the total fuel fired in the furnace will be micronized coal injected in the upper furnace creating a fuel-rich reburn zone. Overfire air will be injected at high velocity for good furnace gas mixing above the reburn zone to ensure complete combustion. Shawnee Station is indicative of a large portion of boilers in TVA's and the nation's utility operating base. Micronized Coal Reburn technology compares favorably with other NOx control technologies and yet offers additional performance benefits. This paper will focus on Micronized Coal Reburn technology and the plans for a full-scale demonstration at Shawnee.*

## INTRODUCTION

According to recent industry studies, 44 percent of the nation's coal-fired plants will have seen their 30th birthday by the turn of the century. Older fossil plants typically have the following operating characteristics and many of these conditions lead to high NOx production:

- Higher excess air
- Deteriorating coal fineness
- Poor control of secondary air
- Mill limited from coal switching
- Poor turn-down ratio
- Cyclic duty operation

TVA has a high boiler population that falls into this category, yet demand upon this existing fossil generating capacity continues. Therefore, TVA has investigated methods of reducing NOx while improving overall boiler performance.

A substantial data base has been developed in the reduction of nitrogen oxides (NOx) by various combustion modifications both here and abroad. Accurate control of coal particle fineness and air fuel ratios are essential ingredients in their success. NOx reduction in existing coal-fired boilers has been demonstrated with either low NOx burners, or reburning with natural gas representing up to 20 percent of the total furnace fuel. Accurate control of the combustion process is common in both NOx reduction methods.

The purpose of this project is to demonstrate the effectiveness of micronized coal (80 percent less than 325 mesh) combined with an advanced coal reburning technology for decreasing NOx emissions by 50 to 60 percent in a 175 MWe pulverized coal wall-fired boiler.

Up to 30 percent of the total fuel fired in the furnace will be micronized coal. This fuel will be injected into the upper furnace creating a fuel-rich zone, at a stoichiometry of 0.8 to 0.9. Overfire air will be injected at high velocity, for good furnace gas mixing, above the reburn zone ensuring an oxidizing zone for an overall furnace stoichiometry of 1.15 (excess air of 15 percent). Micronized Coal Reburn technology reduces NOx emissions with minimal furnace modifications and enhances boiler performance with the improved burning characteristics of micronized coal.

The availability of the reburn fuel, as an additional fuel to the furnace, solves several problems concurrently. Units that are mill limited from fuel switching now have sufficient fuel capacity to reach their maximum continuous rating (MCR). Restoration of lost capacity, as a benefit to NOx reduction, becomes a very economical source of power generation. Reburn burners can also serve as low-load burners and units can achieve a turndown of 8:1 without consuming expensive auxiliary fuels. The combination of micronized coal reburn fuel and better pulverizer performance will increase overall pulverized fuel surface area for better carbon burnout. Micronized Coal Reburn Characteristics and Benefits are highlighted in Figure 1.

Micronized Coal Reburn technology can be applied to cyclone-fired, wall-fired, and tangentially fired pulverized coal units. The overfire air system can also be easily adapted to incorporate in-furnace sorbent injection for $SO_2$ control.

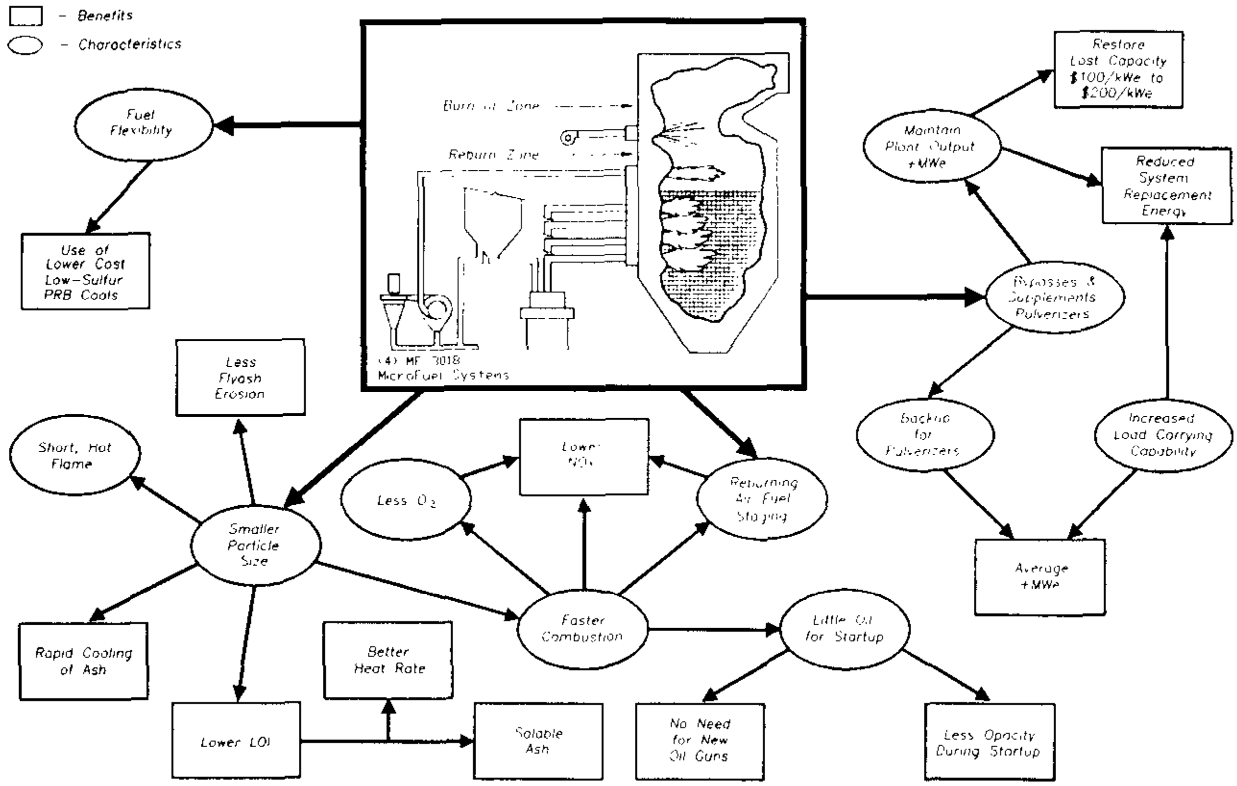



Figure 1

Micronized Coal Reburn Characteristics and Benefits

A baseline test profile of the furnace along with furnace flow and computer modeling will be conducted prior to the design and installation of the MicroMill Systems and micronized coal injector/burners. An extensive test program will document performance during a three-year operational period.

## DOE CLEAN COAL TECHNOLOGY DEMONSTRATION PROGRAM

The Clean Coal Technology Demonstration (CCT) Program is a multi-billion-dollar national commitment, cost-shared by the government and the private sector, to demonstrate economic and environmentally sound methods for using our nation's most abundant energy resource, coal. The program will foster the energy-efficient use of the nation's vast coal resource base. The program will contribute significantly to the long-term energy security of the United States, further the nation's objectives for a cleaner environment, and improve its competitive standing in the international energy market.

The objective of the CCT is to demonstrate a new generation of innovative coal utilization processes in a series of "showcase" facilities built across the country. The program takes the most promising of the advanced coal-based technologies and, over the next decade, moves them into the commercial marketplace through demonstration. These demonstrations are on a scale large enough to generate all the data, from design, construction, and operation, that are necessary for the private sector to judge their commercial potential and make informed, confident decisions on commercial readiness.

The goal of the program is to furnish the U.S. energy marketplace with a number of advanced, more efficient, and environmentally responsive coal-using technologies. The Clean Coal Program is intended to demonstrate innovative technologies that utilize coal in an environmentally superior manner.

Candidate technologies must be capable of either retrofitting, repowering or replacing existing facilities and/or providing for future energy needs in an environmentally acceptable manner. Such existing facilities include coal-fired power generation and industrial processes that utilize coal. The demonstration projects, however, can be at new facilities provided the commercial application of the technology is capable of retrofitting, repowering or replacing applications and/or providing for future energy needs.

When the projects are completed, the sponsors and participants will be in a position to use the information and experience gained during demonstrations to promote and market the technologies in commercial applications. The detailed data and experience will be vital to firms deciding to build retrofit or repower plants using clean coal technologies.

As a part of CCT IV, DOE selected as one of the nine projects to be demonstrated under round IV, TVA's Micronized Coal Reburning at Shawnee. Since NOx, as well as $SO_2$, has been designated by the 1990 Clean Air Amendments passed by the U.S. Congress as precursors of Acid Rain precipitation, controlling NOx has presented challenging problems in achieving a low-cost retrofit control system. To date, there have been several methods used to reduce NOx, however, each with some disadvantages. Low NOx burners have been fairly successful but may not provide sufficient reduction by themselves. Gas reburning also has been successful, but it requires a steady supply of gas at a reasonable cost. Coal reburning shows promise in providing a NOx control system which can be readily retrofitted and operated at low cost. Coal reburning does not require external modifications to the flue gas duct system nor does it require major modifications to the boiler or a separate type of reburn fuel. In fact, coal reburning may help some power producers who have had to derate their unit due to coal switching to meet $SO_2$ reduction requirements.

## PROJECT TEAM

Successful projects are a result of innovative technology with superior and skilled management. An integral part of this combination are the DOE and TVA project team members.

The Department of Energy/Pittsburgh Energy Technology Center (DOE/PETC) will be a co-funder of the project and will work with all the other team members by recommending work emphasis and line of inquiry to accomplish the stated objectives of the project. Also, DOE/PETC will assist in publishing reports and technical information necessary to achieve a commercial success for the project.

The Tennessee Valley Authority (TVA) has assembled a uniquely talented team for this project, including:

- MicroFuel Corporation, Ely, Iowa (MFC), Prime Contractor, Micronized coal technology
  - Research-Cottrell Research & Development, Somerville, NJ (R-C), Furnace modeling, reburn technology
  - Duke/Fluor Daniel, Charlotte, NC (D/FD), Engineering and construction contractor

TVA and each team member bring a unique expertise and experience to the project. Each will provide complementary functions to insure the success of the project. TVA will be the participant and provide the host site, Shawnee Fossil Plant near Paducah, Kentucky. Shawnee Station is currently the site for a DOE CCT III project and was also the host site for a 160 MWe atmospheric fluidized bed combustion demonstration plant. The TVA management staff is well versed and experienced in full-scale technology demonstrations. A Project Organization Chart is shown in Figure 2.

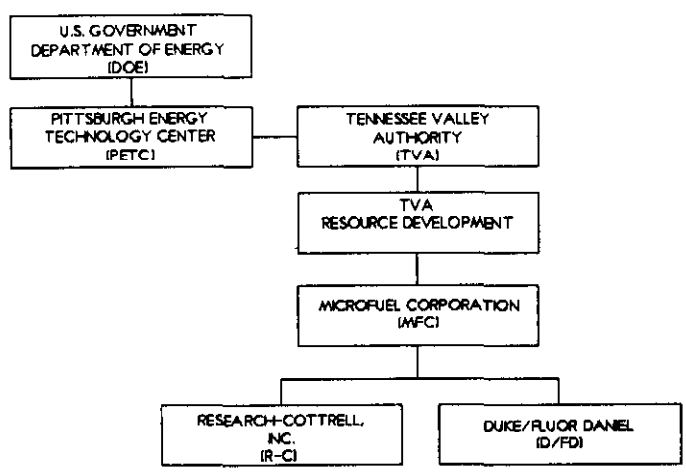



Figure 2

Project Management Team

MicroFuel Corporation (MFC) is the developer of the MicroMill system and has eight years of experience with micronized coal technology. In 1988 MFC installed a nominal 5-ton/hour micronized coal combustion system at Duke Power's Cliffside Station, Unit 5, a 600 MWe unit. The micronized coal combustion system replaced the main oil guns in corners 2 and 4 and has demonstrated the stability of a 100% micronized coal flame in a cold furnace.

Research-Cottrell Research & Development (R-C) has been a pioneer in NOx control and a leader in the development of advanced reburn technology. R-C will provide engineering and R&D support, including computer and cold flow boiler modeling, and emissions monitoring and laboratory analysis. Developing NOx control methods for major utilities nationwide has provided R-C with extensive knowledge and experience in both combustion and post-combustion NOx reduction techniques. At their Western Research Facility (formerly KVB), low NOx burners have been designed and test-fired correlating fuel burnout, ignition behavior, and NOx emissions as a function of burner geometry and swirl levels.

In addition, R-C is familiar with the TVA Shawnee test facility, having conducted a study of flue gas desulfurization by spray dryer and electron beam in 1983-84. Trials were performed with both fabric filter and an electrostatic precipitator as the particulate control device.

Duke/Fluor Daniel (D/FD) will provide architectural and engineering services to facilitate construction and integration of the boiler systems. As the engineer constructor, D/FD combines Duke Power's 65 years of experience and the resources and experience of Fluor Daniel in coal power plant design, construction and operation. In addition, D/FD was the engineer construction manager on TVA's 160 MWe atmospheric fluid bed demonstration project at Shawnee.

## SITE

### Site Description

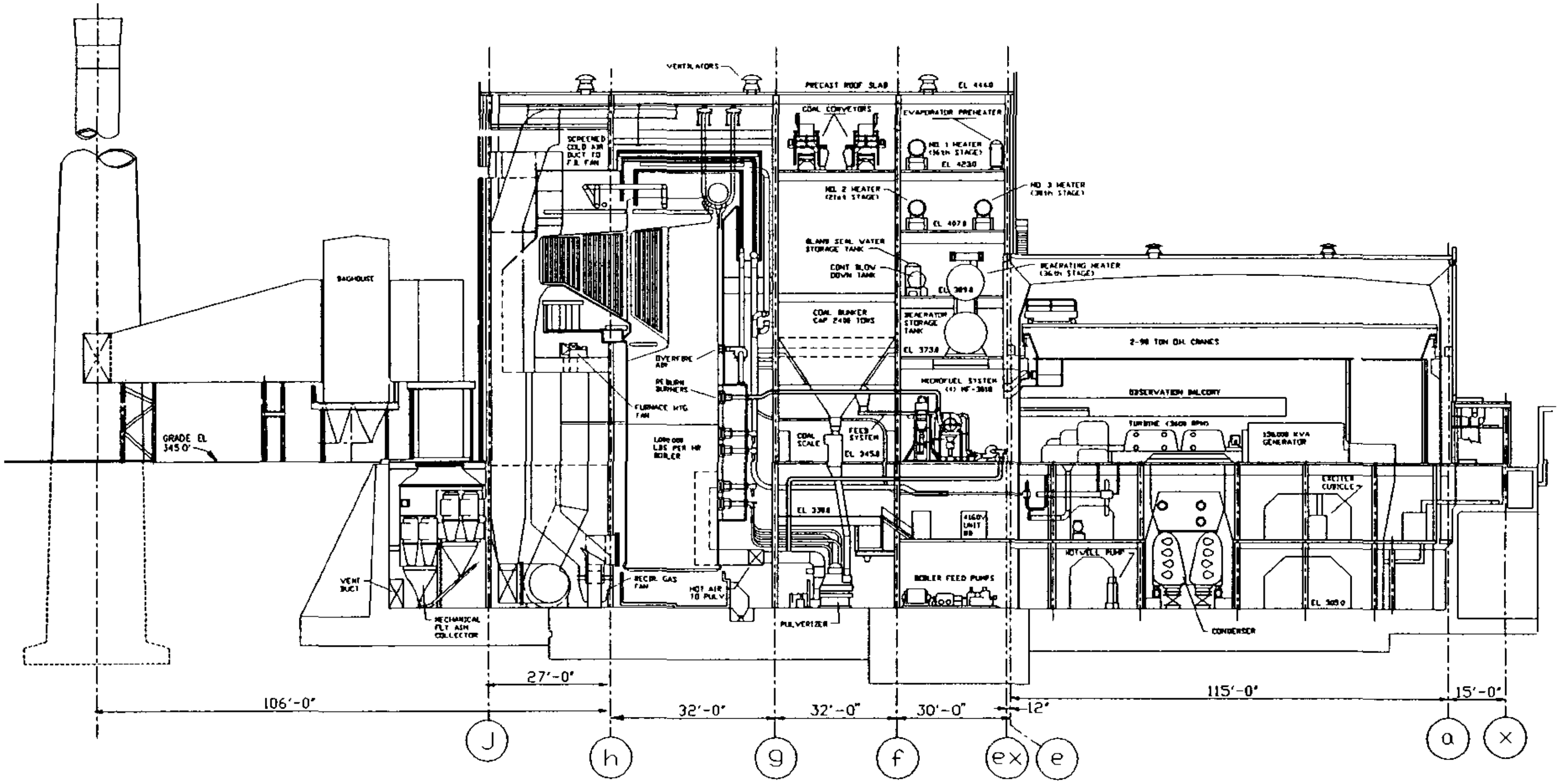
The host site will be one of units 1-9 at TVA's Shawnee Fossil Plant which was built to help meet the huge electric power requirements of a nearby DOE facility. Construction began in January 1951 and commercial operation commenced in April 1953. By October 1956 all 10 of the plant's identical pulverized coal-burning units were generating power.

Although Shawnee is approaching 40 years of operation, it still has the capacity to generate approximately 11 billion kilowatt-hours of electricity each year. Despite its age, the plant has a lifetime generation availability of greater than 91 percent. The Shawnee facilities have also been a testing center for the development of pollution control technology. Over the years limestone furnace injection and a variety of wet scrubbers have been demonstrated for $SO_2$ removal. Fluidized bed combustion has been demonstrated first with an atmospheric fluidized bed combustion (AFBC) 20 MWe pilot plant since 1982 and more recently with a 160 MWe commercial scale unit (unit 10). Presently emission control for the conventional pulverized coal-fired units (units 1 through 9) consist of low sulfur coal (1.195 lb $SO_2/10^6$ Btu), and fabric filters for particulate control.

Each boiler is a 175 MWe (gross) front wall-fired dry-bottom furnace burning East Appalachian low-sulfur coal. A cross sectional general arrangement of a typical unit with Micronized Coal Reburn system in place is shown in Figure 3. The plant was originally designed to burn high-sulfur coal, but in the 1970s, the plant was modified to burn low-sulfur coal in order to meet an emission limit of 1.2 lbs $SO_2/10^6$ Btu of heat input without the use of any sulfur dioxide control technology. Each unit has been equipped with a baghouse to control particulate emissions. Flue gas from each unit discharges to one of two 800-foot stacks also constructed in the 1970s. The original electrostatic precipitator short-stack system has been removed from service. The nine existing pulverized coal units are representative of a large number of wall-fired units in the industry which will be required to reduce NOx emissions in response to the 1990 Clean Air Act Amendments.

### Ash Handling

In the past, fly ash and bottom ash from all 10 units at the Shawnee Fossil Plant were sluiced to an ash pond for disposal. The ash pond was periodically dredged to dry storage in order to prolong the useful life of the pond. Plant facilities recently have been modified to allow dry handling and disposal of fly ash from the pulverized coal units and spent bed material from the AFBC unit. If the demonstration achieves a secondary goal of reducing carbon in the ash when combined with dry handling, market potential in the ash will increase.

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| Tennessee Valley Authority | | |
| DWG. No. 25-0008 (Ref. SHF47213) | | |
| D.O.E. PON DE-PS01-91FE62271 | | |
| TVA Shawnee Station Unit 6<br>Micronized Coal Reburn Demonstration<br>NOx Control-175 MW Wall Fired Unit<br>Mechanical Equipment Traverse Section | | |
| Date | 04/30/91 | DLS |

Figure 3

### Coal Acquisition

TVA has contracts in place to supply Shawnee with low-sulfur bituminous coals from Kentucky and West Virginia. These coals will be used as the primary fuels for the project. TVA has test burned western coals such as Powder River Basin (PRB) at a number of sites, including Shawnee, since the late 1970s. PRB coal will be obtained for testing for this demonstration. Installing four nominal 5-ton/hour MicroMills will offset the furnace derating effect of PRB coal with its lower heating value.

The Shawnee units typically cycle between minimum and maximum load daily. This will provide opportunities for data collection under varying conditions and demonstration of the capabilities of the MicroMill Systems and burners to allow operation at very large turndown ratios without supplemental firing.

## REBURN CONCEPT

### History of Technology

Reburning is a combustion modification technology that removes NOx from combustion products by using a hydrocarbon fuel as the reducing agent. This technology, which is alternately referred to as "in-furnace NOx reduction" or "staged fuel injection," has been found to involve kinetic processes similar to those in staged combustion. The concept was originally developed by the John Zink Company and Wendt, et al., based on the principle of Myerson, et al., that CH fragments can react with NO. More recently several investigators have conducted detailed investigations of the process and demonstrated its potential for large-scale applications. See list of references in Attachment A.

### Process Chemistry

Reburning is a process where a fraction of the fuel is injected downstream of the main combustion zone to form a fuel-rich zone. Additional air is needed further downstream to complete combustion. The reburning process consists of three main zones: the primary or main burner zone, the reburn zone, and the burnout zone, as shown schematically in Figure 4. Details of the process in the various zones are as follows:

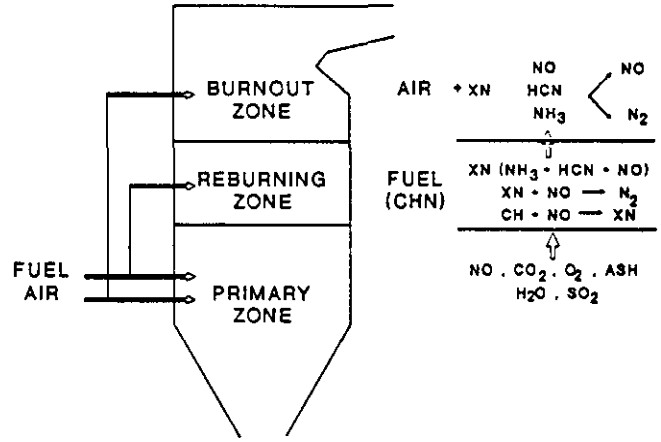



Figure 4

Chemistry of Reburn Process

<u>Primary Zone</u> This is the zone where the main fuel normally enters the furnace through one or multiple burners. These burners may be mounted on the front or rear walls, or both walls, or in the corners (tangential firing). In utility-sized furnaces the fuel enters in a horizontal direction, combustion occurs, and the products of combustion then turn and move upward in a vertical direction. Normally the fuel burns with an excess amount of air (fuel-lean) to assure good combustion performance. The fuels used in this type of furnace are gaseous, liquid, or solid (pulverized coal, normally 70 percent through 200 mesh or nominally 60 microns). This is the zone where NOx is formed from fuel nitrogen and air fixation mechanisms. Under reburning the amount of fuel entering this zone is reduced to approximately 70 to 80 percent of the total heat input to the system. The fuel is combusted under a fuel-lean condition but the amount of excess air can be reduced without impact on combustion efficiency because of the other zones of the reburn process.

<u>Reburning Zone</u> Reburning fuel is injected in a horizontal direction downstream of the primary zone to form a fuel-rich mixture. The reburn fuel may be gaseous, liquid or solid. In this reburn process the reburn fuel is micronized coal, 80 percent through 325 mesh or nominally 20 microns. The three major reactions occurring in the reburning zone are:

1. NO reacts with hydrocarbon radicals in reactions such as:

$$NO + CH \rightarrow N + CHO$$
$$\rightarrow HCN + O$$

which increases the nitrogen radical pool.

2. Interconversion of nitrogen species among different fixed nitrogen compounds (NO, HCN, or $NH_3$) occurs. (In this paper, the expression XN is used to refer generically to any of these three fixed nitrogen species.)

3. The formation of molecular nitrogen by the reaction of nitrogen radicals with NO.

$$NO + N \rightarrow N_2 + O$$

The latter reaction, sometimes referred to as the "back-Zeldovich" reaction mechanism, is the most probable path, although reactions with $NH_2$ species are possible. Consequently, the nitrogen oxide formed in the primary zone is either converted to $N_2$ $NH_3$, HCN, or retained as NO. When the reburning fuel contains nitrogen (e.g., if the reburning fuel is coal), coal nitrogen could remain with the char or form NO, HCN, and $NH_3$. Thus, the products of this zone contain nitrogen species which can be converted to NO, (namely char nitrogen) $NH_3$, and HCN, as well as NO. The sum of these gas-phase species is referred to as total fixed nitrogen (TFN).

Burnout Zone In this zone air is added to produce an overall air-rich (fuel-lean) condition to complete the combustion of all the remaining fuel. The TFN or char nitrogen is converted to NO or $N_2$. This zone is analogous to the second stage of a staged-combustion process. The resultant NOx leaving this zone is substantially less than the NOx formed in the primary zone and also less than formed in a conventional furnace.

Typically the stoichiometry in the primary zone is between 1.0 and 1.1 (0 and 10 percent excess air) to minimize NOx while not producing a zone that may result in slagging or corrosion and also combustible burnout problems. The reburn zone would normally be operated at a stoichiometry between 0.8 and 0.9. The air used for dispersion of the micronized coal through the coal injector would be preheated air (secondary air) from the windbox. The coal injector will require that the micronized coal be distributed across the furnace to mix with the furnace gas in the reburn zone and then with the overfire air in the burnout zone.

**Concept Operation**

Micronized coal reburning for NOx control will operate in the same manner as natural gas reburning on coal-fired boilers. In effect, the entire furnace operates as a low NOx burner. The existing burners shall be operated slightly oxidizing with accurate fuel/air control. Microfine coal, with a surface area of 31 $m^2/gm$ is fired substoichiometrically in a reburn zone above the top row of the existing burners. Combustion of the high-surface-area micronized coal consumes oxygen very rapidly converting NOx to molecular nitrogen. NOx conversion occurs with a residence time of 0.5 to 0.6 seconds. Above the reburn zone high velocity overfire air will uniformly mix with the sub-stoichiometric furnace gas to complete combustion, giving a total excess air ratio of 1.15. This concept should reduce NOx emissions 50 to 60 percent from current levels of 0.82 to 0.95 $lbs/10^6Btu$ to an emission level of 0.33 to 0.48 $lbs/10^6Btu$.

The proposed project will demonstrate the effectiveness of reducing nitrogen oxide emissions with an advanced coal reburning technology utilizing micronized coal. This technology can be applied in new as well as existing pulverized coal-fired furnaces. The coal used in reburning can be the same coal as used in the main fuel burners. A schematic of this system is shown in Figure 5. In addition, this reburn technology can be combined with various sulfur dioxide ($SO_2$) control technologies such as fuel switching, dry sorbent injection, or other post combustion technologies.

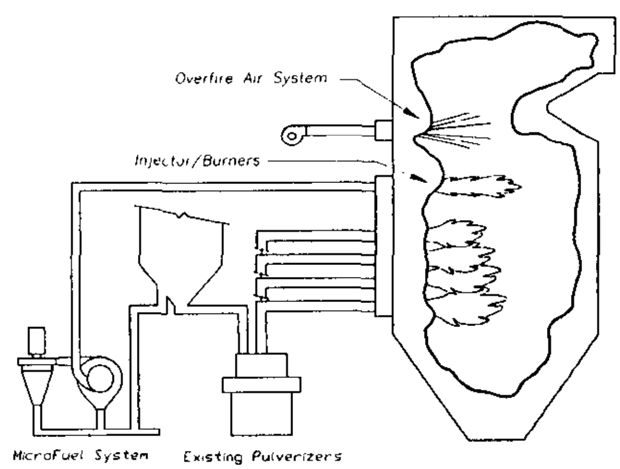
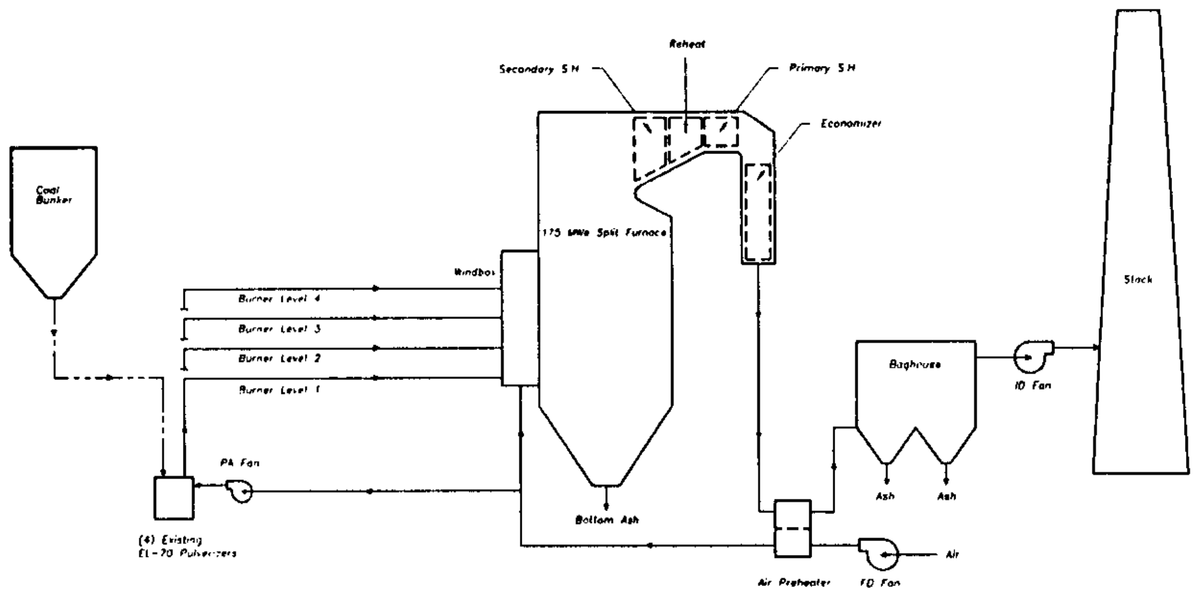



Figure 5

Schematic of Reburn Process

The original design coal for Shawnee had a Hardgrove Index (HGI) of 50. By converting to east Appalachia low sulfur coal with an HGI of 36 to 44, the units are mill limited to 154 MWe when coal moisture is high. The reburn system providing approximately 20 ton/hour of micronized coal milling capacity would maintain boiler maximum continunig rating (MCR). Other advantages would include improved opacity on start-up, a much higher turndown ratio (8:1), and improved LOI (Loss on Ignition).

With the furnace operating at an MCR of 154 MWe, the coal/air flows for each burner level are shown in Figure 6. The heat input for each level is shown along with the percentage of the total heat input, the air flow by level, and the stoichiometry.




GROSS UNIT OPERATING CAPACITY 154 MWe

| Furnace Level | Level 1 | Level 2 | Level 3 | Level 4 | Total |
|---|---|---|---|---|---|
| Coal, lbs/hr | 28,250 | 28,250 | 28,250 | 28,250 | 113,000 |
| MMBTU/hr | 346.5 | 346.5 | 346.5 | 346.5 | 1,386 |
| Percent of Total | 25.0 | 25.0 | 25.0 | 25.0 | 100 |
| Air, lbs/hr | 351,920 | 351,920 | 351,920 | 351,920 | 1,407,680 |
| Stoichiometry | 1.21 | 1.21 | 1.21 | 1.21 | 1.21 |

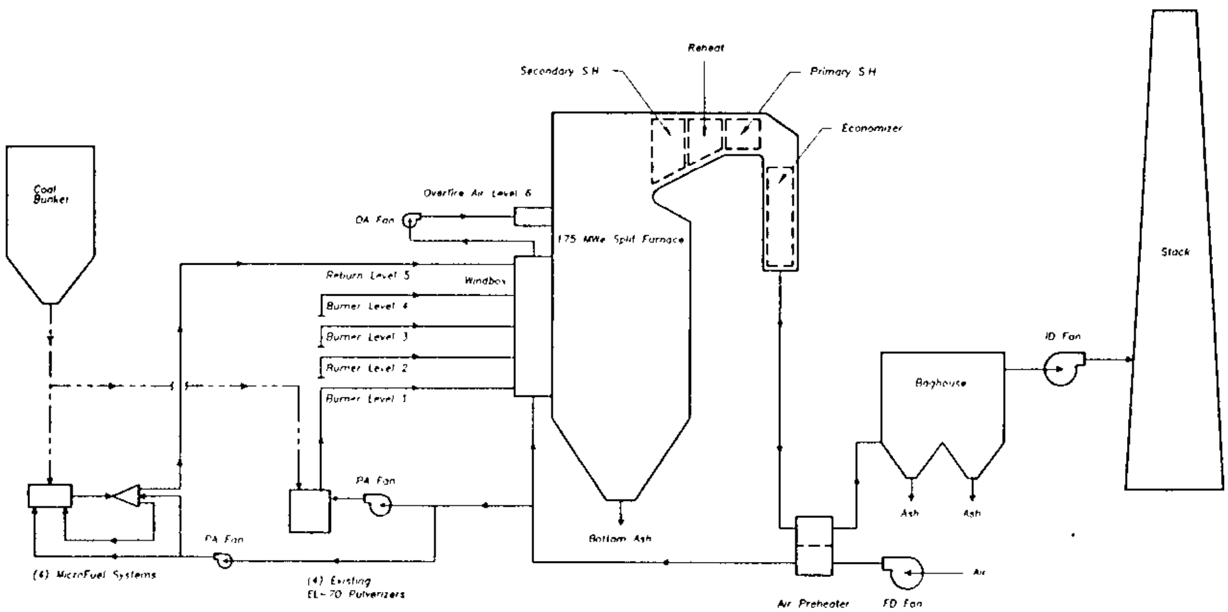
Eastern Kentucky Coal - 12,264 BTU/lb



Figure 6

Block-flow Diagram - Eastern Kentucky Coal, 154 MWe Gross Unit Operating Capacity

Figure 7 shows the Micronized Coal Reburn System with reburn fuel at level 5 and overfire air at level 6. The total heat input has been increased, and thus the operating capacity is shown at a gross MCR of 175 MWe. The units at Shawnee have excess turbine generator capability but may be limited by boiler feed water flow and permitted heat input limits. These issues will be addressed during the operational phase and the benefits of additional capacity will be weighed against current operating criteria.




GROSS UNIT OPERATING CAPACITY 175 MWe

| Furnace Level | Level 1 | Level 2 | Level 3 | Level 4 | Level 5 | Level 6 | Total |
|---|---|---|---|---|---|---|---|
| Coal, lbs/hr | 25,000 | 25,000 | 22,000 | 21,000 | 35,000 | ---- | 128,000 |
| MMBTU/hr | 306.6 | 306.6 | 269.8 | 257.5 | 429.2 | ---- | 1,570 |
| Percent of Total | 19.5 | 19.5 | 17.2 | 16.4 | 27.4 | ---- | 100 |
| Air, lbs/hr | 270,300 | 270,300 | 237,900 | 227,100 | 48,600 | 461,800 | 1,516,000 |
| Stoichiometry | 1.05 | 1.05 | 1.05 | 1.05 | .80 | 1.15 | 1.15 |

Eastern Kentucky Coal - 12,264 BTU/lb

Figure 7

Block-flow Diagram - Eastern Kentucky Coal, 175 MWe Gross Unit Operating Capacity

The addition of MicroMill systems will increase total heat input and will allow classifier settings on existing pulverizers to be adjusted for improved fineness relating directly to combustion efficiency and lower LOI. Stoichiometry in the lower furnace is maintained at 1.05 (5.0 percent excess air) to assure an oxidizing zone and minimize slagging and corrosion. The stoichiometry at burner level 5, the reburn level, is 0.8 to 0.9 and with the addition of overfire air at level 6, the furnace will have an exiting stoichiometry of 1.15 (15 percent excess air), compared to the current operating condition of 1.21 (21 percent excess air). Thus, the micronized coal reburn system not only reduces NOx emissions but also improves boiler efficiency and increases boiler capacity.

### Process Advantages

The following advantages of micronized coal reburning for NOx control compare favorably with other NOx control technologies.

- Economical Fuel - Reburning is a recognized effective technology for controlling NOx emissions in a pulverized coal-fired boiler. Most of the reburning activity to date has been with natural gas or oil as the reburn fuel. Although both fuels have demonstrated effectiveness, they are subject to one or more of the following disadvantages:
  - Availability, especially in winter
  - Unstable/escalating fuel cost
  - Operational problems firing dual fuels
  - Reduced boiler efficiency due to hydrogen in fuel
- Flexibility - The technology is flexible enough to combine with other NOx control micronized coal reburn technologies and reduce NOx emissions to required lower levels.
  - Site Specific Benefits
  - Reduced energy replacement costs due to improved ability to operate at a rated load even with wet coals and/or equipment problems (mills, feeders).
  - Reduced capacity costs due to increased power generation.
  - Increased fuel flexibility allowing use of lower quality coals while mitigating deratings caused by fuel handling limitations.
  - The ability to operate existing pulverizers at reduced throughput without loss in capacity will improve coal fineness and possibly reduce unburned combustible in ash, thus increasing value of the ash as a marketable commodity.
  - Improved turndown and stability at low loads without firing supplemental fuels; and maintaining superheater outlet temperatures at low loads.
  - Knowledge gained from this demonstration can be used to scale up the Micronized Coal Reburn technology for installation on TVA's Allen Fossil Plant (330 MWe cyclone fired).

### NOx Control Strategy

A majority of the 300,000 MWe generated by coal-fired utility units will be impacted by the 1990 Clean Air Act Amendments requiring reduction of NOx emissions. It is unlikely that one NOx control method will meet the needs of this diverse boiler population. NOx control strategies fall into two major categories: Combustion modification and post combustion technologies.

Combustion modification includes low NOx burners, reburning and fuel air staging. The post combustion options are selective noncatalytic reduction (SNCR) using reagents such as ammonia or urea and selective catalytic reduction (SCR) using both reagent injections and catalysts.

In selecting an NOx control strategy for a given unit, utility engineers must weigh many factors including the type of unit, operating requirements and unit design ratings versus current operating capabilities. Most utilities will probably select some form of combustion modification as their preferred NOx control method. Many utilities, already familiar with pulverized coal burners and burner management systems, will elect to install low NOx burners as the method of controlling the combustion process.

There is, however, a large population of utility boilers for which reburning is an attractive option. Wet bottom furnaces such as cyclones and some wall-fired furnaces that operate in a slagging mode are obvious choices for reburning, and the addition of a micronized coal reburn system can be utilized in such diverse applications as start-up, low load operation and restoring lost capacity. Units that operate at very low loads for long periods of time, units that are relegated to cyclic duty, and units that have pulverizer load limitations resulting from fuel switching are all very good candidates for reburning as a primary NOx control method.

## SUPPORTING ACTIVITIES

While the Micronized Coal Reburn system is in a state of technical readiness for full-scale demonstration, there will be several supporting activities to ensure a high degree of success for the demonstration. Among these activities are furnace cold-flow and computer modeling. The modeling will be conducted in the first phase and will provide even further evidence of adequacy, availability, suitability, and quality of the data and analysis to support the full-scale demonstration.

Diagnostic tests will be conducted to determine temperature and velocity patterns in the furnace, supplementing similar previous tests in another unit at the plant with different burner registers. Boiler performance tests will also be conducted providing flue gas flow rate, gas composition, and unburned combustibles. These tests will be used to initiate preliminary design of the reburn injector/burners and overfire air nozzles. A 1:8 scale cold-flow model will be built to simulate the existing burner windbox assembly, burners and air registers as well as the furnace flow regime, including the lower and upper furnace past the furnace nose and into the convection section. This flow model will permit determination of the number and location of both the reburn injector/burners and overfire air nozzles. The flow model will compare front versus rear-wall locations and also a combination of both. The cold-flow model will be designed, fabricated and tested at R-C's Fluid Dynamic Laboratory. With the cold-flow model existing windbox, burner and furnace flow patterns can be observed. In addition, the model will provide an easy, convenient model to vary the number and location of the reburn injector/burners, overfire air windbox, and nozzles to assure dispersion and mixing of the micronized coal in the reburn zone and the overfire air in the burnout zone. The cold flow model will also be available during Phase 3 of the test program in the event any fine tuning of the reburn system is required. The computer modeling of the furnace will provide not only screening for the cold-flow model but also predict reburn system performance on the furnace and boiler as well as the effect of heat release and mixing in the reburn zone.

Once the flow and mixing characteristics have been determined from the modeling activities, the reburn injector/reburner will be designed. The design will accommodate these flow characteristics while achieving local mixing of the micronized coal-air stream from the injector to achieve combustion at a prescribed fuel-rich condition (0.8 stoichiometry) as well as a micronized coal burner at normal fuel-lean condition. The latter condition is desired to achieve a high turndown ratio or as a conventional burner in the event that the conventional pulverizers are out of service. A single micronized coal injector/burner will be tested in R-C's Test Simulator. These supporting activities will then be utilized for the overall system design for the full-scale demonstration.

## MICRONIZED COAL TECHNOLOGY

### Technology Description

The technology described in this paper is a combination of a technology that produces micro-fine coal reliably and economically, with a known NOx control technology (fuel reburning). When micronized coal is fired at a stoichiometry of 0.8 to 1.2, devolatilization and carbon conversion occur rapidly.

Micronized coal is defined as coal ground to a particle size of 43 microns or smaller. The Micro-Fuel System, consisting of the MicroMill and an external classifier, micronizes coal to a particle range of 10 to 20 microns. Figure 8 displays a typical particle distribution curve.

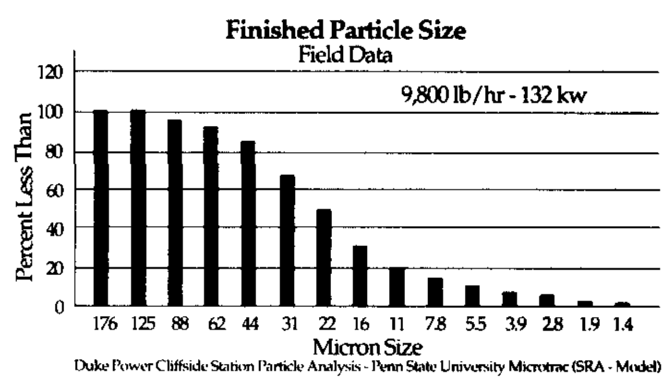



Figure 8

For a given volume of material, the surface area doubles for every three (3) micron reduction in mean particle diameter. Figure 9 shows the relationship between particle diameter/particle count versus a given volume.

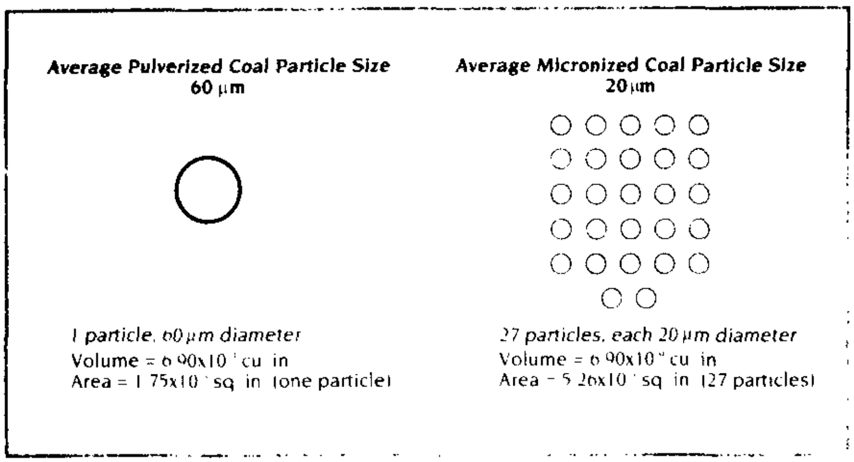



Figure 8

Micronized and Pulverized Coal Particle Size Comparisons

The combined surface area of just one gram of micronized coal particles is 31 square meters, contrasted to a surface area of 2.5 square meters per gram for pulverized coal.

The heart of the MicroFuel System is a patented centrifugal-pneumatic MicroMill, with only one moving part, the replaceable rotating impeller. Size reduction is accomplished, not by pressure crushing or hammer impacting, but by the particles themselves striking against one another as they whirl in a tornado-like column of air inside the MicroMill. Centrifugal force retains material in the rotational impact zone (RIZ) as the particles reduce in size prior to being conveyed by the air stream entering the center of the rotating impeller. Figure 10 is a sectional view of the MicroMill and Figure 11 is a cut-away view of the MF-3018 MicroMill.

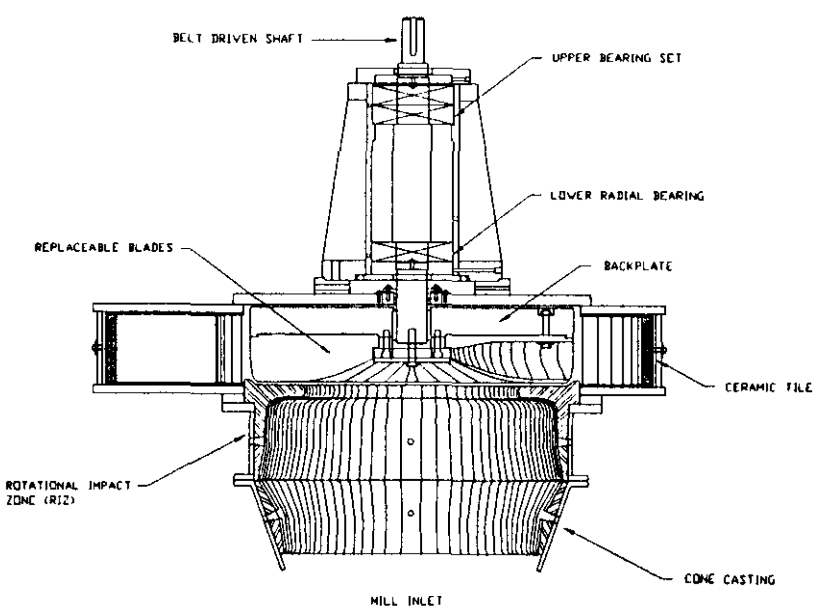



Figure 10

Sectional View of MicroMill

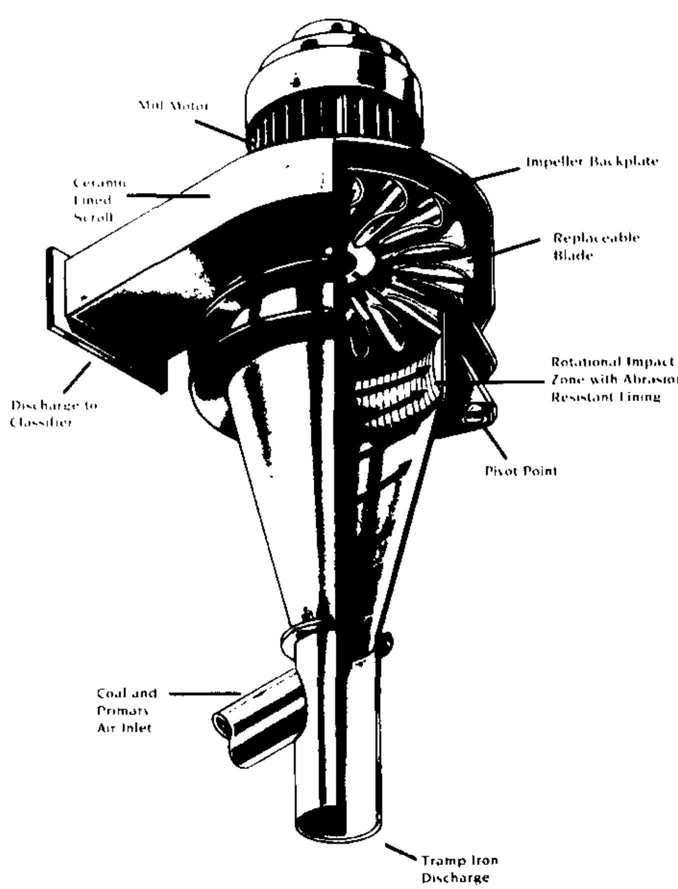



Figure 11

Cut-Away View of MicroMill

Material entering the impeller is swept out of the MicroMill to the classifier, which separates particles by size. Micronized coal particles below 43 microns are discharged directly to the burners, and larger particles are returned to the MicroMill for further size reduction. Figure 12 is a dimensional elevation of a complete MicroMill system.

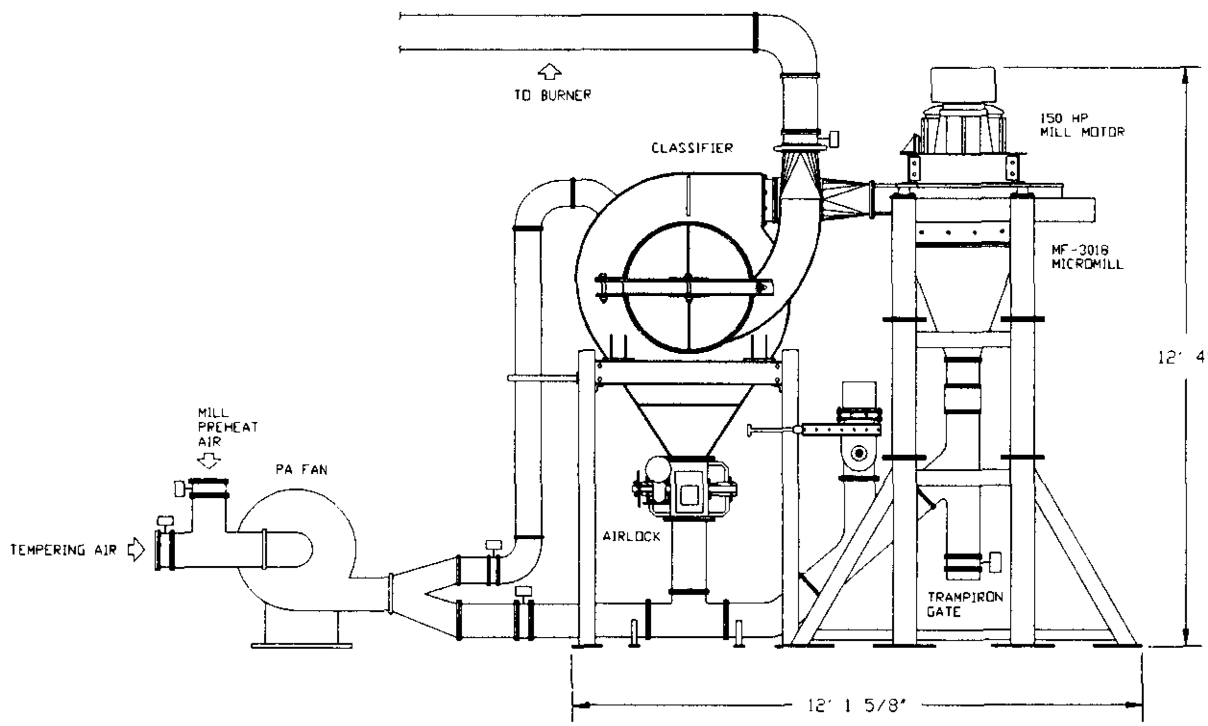



Figure 12

Dimensional Elevation, General Arrangement, MF-3018 MicroMill System

Because of its simple design, the MicroMill is easy to operate and maintain. For a given amount of energy, it produces significantly more surface area for combustion than conventional coal pulverizers. The micronizing process produces a dramatic increase in the surface area per weight of coal, resulting in a more stable, controllable combustion reaction. All chemical reactions, including combustion, require that the surfaces of different substances come in direct contact. The rate of any chemical reaction varies predictably, based on the nature of the substances involved and the conditions, such as temperature and pressure, under which the reaction takes place. But in any case, it is directly proportional to the size of the contact area between the substances involved in the reaction. In combustion, these substances are the fuel and the combustion air.

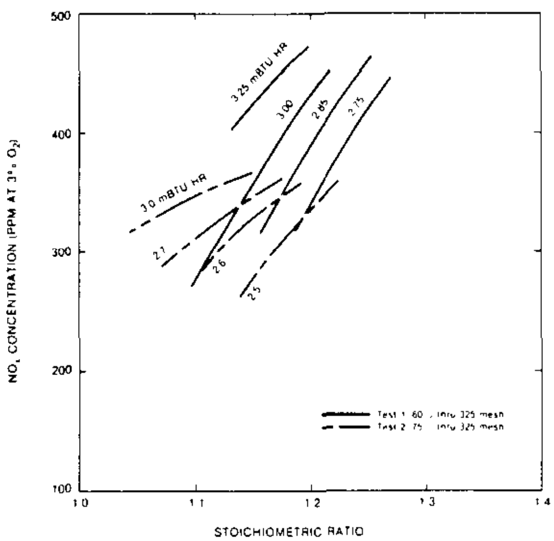



Figure 13

Effect of Excess Air and Coal Size on NOx Emissions

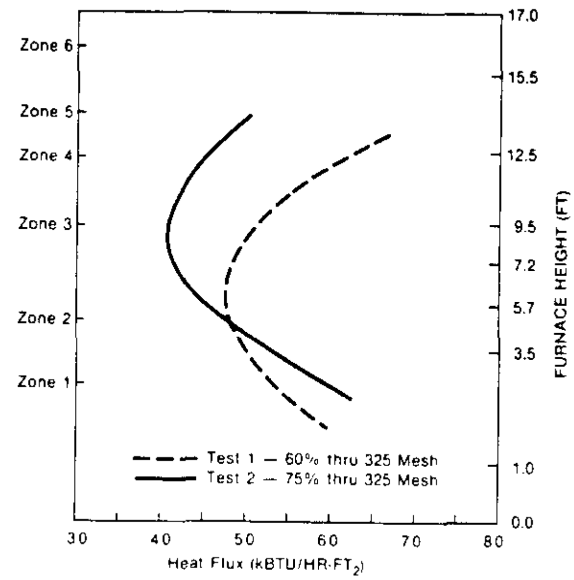



Figure 14

Effect of Coal Size on Furnace Heat Flux

The net result of this reaction is a uniform compact combustion envelope allowing for complete combustion of the coal/air mixture in a smaller furnace volume than conventional pulverized coal. Heat rate, heat flux, carbon loss, and NOx formation are all impacted by coal fineness.

## ENVIRONMENTAL ASPECTS

With the exception of significant reductions in NOx emissions, the environmental impact of the proposed project is inconsequential. As a result, no new permits or licenses will be necessary to implement the proposal. Application of the Micronized Coal Reburn system is projected to reduce NOx emissions by 50 to 60 percent on a mass basis, from 1,943 tons/year to 874 tons/year, based on a capacity factor of 40 percent.

Shawnee currently burns low-sulfur Appalachian coal (1.195 lb $SO_2/10^6$ Btu). Lower-sulfur western coal (0.35 lb $SO_2/10^6$ Btu) will be burned briefly as part of the demonstration. During that period, $SO_2$ emissions will be further reduced. The use of eastern low-sulfur coals with reduced grindability has made the existing pulverizers marginal. Equipment problems or wet coal will result in further derating of the unit. The introduction of Micronized Coal Reburning as an additional fuel will allow Shawnee to overcome mill limitations and operate at somewhat higher capacity factors. This may result in a slight increase in total emissions on a mass basis, but emissions concentration will remain unchanged.

### Reduction/Control of Greenhouse Gases and Air Toxics

No significant changes in the emissions of greenhouse gases or air toxics are projected. A minor increase in the emissions of CO and hydrocarbons may occur at times during the demonstration as parametric testing may occasionally result in slightly less than complete combustion. However, existing pollution control equipment should be able to maintain emission levels within regulatory limits. Emissions monitoring will be performed to ensure continued compliance.

No new waste products will be generated by the Micronized Coal Reburn process, as no reagents are utilized. Existing requirements for fly ash and bottom ash disposal are expected to remain constant. Current water usage by the unit averages 3.1 million gallons per day for ash sluicing, and no change is projected for the purposes of the demonstration. Average fly ash particle size will decrease slightly, but existing baghouses will efficiently collect fly ash.

### EHSS Compliance/Risk and Impact

Since this demonstration will cause no significant increases in emissions, TVA has applied for and expects to receive a categorical exclusion. Emissions will remain within permitted limits.

No risks or adverse impacts to human and animal health and safety or to geographic features are anticipated. *It is predicted that the objective of this* demonstration, reduction of NOx emissions, will be the only significant environmental effect. No impacts on land or water quality are anticipated except as a modest reduction in precursors to acid rain formation.

The primary socioeconomic effect of this project is expected to be favorable: the demonstration of a high degree of NOx reduction at relatively low costs. No significant changes in personnel requirements or operating inputs at the plant are projected.

## PREOPERATIONAL AND OPERATIONAL TESTING

Pre-operational testing will be conducted to include characterization of various aspects of the system, particularly the newly designed components. Parametric testing will document the effect of the following reburn system variables:

- Primary burner zone stoichiometry
- Reburn zone stoichiometry
- Final (burnout zone) stoichiometry
- Reburn zone momentum
- Micronized coal consumption in main burners
- Reburn fuel particle size
- Reburn zone injection with flue gas recirculation
- Load
- Coal composition

This data will permit the determination of optimal conditions for achieving various levels of NOx reduction, boiler efficiency, operating and maintenance requirements.

### Long-Term Testing

Boiler performance with the reburn system will be documented over a three-year period to identify long-term trends in emissions and boiler behavior. Monitoring of flue gas will be by a Continuous Emissions Monitor (CEM). The objective of all monitoring functions will be to assess:

- NO, $NO_2$, $O_2$, CO, $CO_2$, and $SO_2$ emissions
- Particulate emissions
- Emissions during transients
- Unburned carbon in flue gas and fly ash
- Pulverizer/mill performance
- Coal flow rate and size distribution
- Air preheater performance
- Boiler slagging and fouling
- Waterwall and convective pass corrosion
- Furnace temperature profile
- Boiler thermal efficiency
- Combustion system reliability
- Boiler load response

All CEM and boiler operation signals which can be efficiently monitored in real time will be directly stored on disk. The database will permit ready and efficient reduction and analysis of the data, both during execution of the program and during final analysis and evaluation. Information from the long-term test will permit evaluation of system efficiency and reliability under real conditions. Also, the extended operating period will provide data for projecting economic impacts.

## CONCLUSIONS

TVA has a strong history of leadership in the development of new and emerging technologies and the performance of successful R&D programs. TVA believes that this nitrogen oxide emission control technology shows sufficient benefit to its own system as well as the utility industry in general to take the leadership position in sponsoring a Micronized Coal Reburn Demonstration.

The combination of micronized coal supplying up to 30 percent of the total furnace requirements and reburning for NOx control will provide flexibility for significant environmental improvement without adding higher operating costs or furnace performance deratings normally associated with environmental controls.

By meeting the objectives of this important coal reburning project, coal will be shown to be its own best friend in controlling NOx emissions and providing economical power to the public well into the future.

## Attachment A

- **Reburn Technology for Boiler NOx Control** by R.W. Borio of Combustion Engineering, Inc., R.E. Hall of U.S. Environmental Protection Agency, R.A. Lott of Gas Research Institute, A. Kokkinos of Electric Power Research Institute, and S. Durrani of Ohio Edison. Presented at the 6th Annual Coal Preparation, Utilization and Environmental Control Contractors Conference.
- **An Evaluation of Natural Gas Cofiring for Emissions Control on a Coal-Fired Boiler** by P.K. Vitta, S.M. Wilson, M.T. Newton, M.D. Conner of Souther Company Services, Inc. Presented at the ASME International Joint Power Generation Conference 1990.
- **Preliminary Study of the Effects of Natural Gas Co-Firing on Coal Particle Combustion** by A.R. Schroeder, D.A. Thompson, H. Krier, J.E. Peters and R.O. Buckius of the Department of Mechanical and Industrial Engineering, University of Illinois.
- **Results of Combustion Modification for the Reduction of NOx Emission** by K.R.G. Hein and G. Jager of RWE Energie AG, Germany, Presented at the Joint ASME/IEEE Joint Power Generation Conference, 1990.
- **New Steam Generators with Low NOx Pulverized-Coal Firing** by K. Straub and F. Thelen, of Steag AG, Germany, Presented at the Joint ASME/IEEE Power Generation Conference, 1990.
- **Review of Research Activities on Pulverized Coal Firing Systems** by F. Adrian of L&C Steinmuller GmbH, West Germany. Presented at the Joint ASME/IEEE Power Generation Conference, 1990.
- **Pilot Scale Process Evaluation of Reburning for In-Furnace NOx Reduction** by J.M. McCarthy, B.J. Overmoe, S.L. Chen, W.R. Seeker and D.W. Pershing of Energy and Environmental Research Corporation, Irvine, California, Presented at the Joint ASME/IEEE Power Generation Conference, 1990.
- **Micronized Coal Technology: Process & Potential Applications** by Allen C. Wiley of MicroFuel Corporation, Ely, Iowa, presented at the 4th Annual Pittsburgh Coal Conference, 1987.
- **Micronized Coal for Boiler Upgrade/Retrofit. Duke Power Coal Start-up Tests** by A.C. Wiley of MicroFuel Corporation, T. Rogers and M. Beam of Duke Power Company, and L. Berry of Peabody Engineering Company, Presented at Gen-Upgrade 90.
- **Micronized Coal for Boiler Upgrade/Retrofit. Duke Power Coal Start-up Tests, Update and Results** by A.C. Wiley of MicroFuel Corporation, T. Rogers and M. Beam of Duke Power Company, and L. Berry of Peabody Engineering Company, Presented at Power Gen Conference, 1990.
- **Technical and Economic Feasibility for the Application of Micronized Coal as a Replacement for Number 2 Oil for Start-up and Low-Load Operation at Illinois Power Havana #6 Cycling Unit** by F. Rosenberger of Illinois Power Company, C.J. Guilfoyle of Sargent & Lundy, and W.O. Parker, Jr. of MicroFuel Corporation, presented at American Power Conference, 1991.
- **Bench and Pilot Scale Process Evaluation of Reburning for In-Furnace NOx Reduction** by S.L. Chen, J.M. McCarthy, W.D. Clark, M.P. Heap, W.R. Seekez, D.W. Pershing, Twenty-First Symposium (International) on Combustion, The Combustion Institute, 1986, p.1159-1169.
- Process for the Disposal of Nitrogen Oxide by R.D. Reed of John Zink Company, U.S. Patent 1,274,637, 1969.
- Fourteenth Symposium (International) on Combustion, p. 897, by J.O. Wendt, C.V. Sternling and M.A. Matovich, The Combustion Institute, 1973.
- Sixth Symposium (International) on Combustion, p. 154, by A.L. Myerson, F.R. Taylor and B. Faunce, The Combustion Institute, 1957.
- **Development of Mitsubishi "MACT" In-Furnace NOx Removal Process** by Y. Takahashi, et al., presented at U.S.-Japan NOx Information Exchange, Tokyo, Japan, May, 1981.
- **Evaluation of In-Furnace NOx Reduction** by S. Miyamae, H. Ikebe and K. Makino, Proceedings of the 1985 Joint Symposium on Stationary Combustion NOx Control, 1986.
- **Three-Stage Pulverized Coal Combustion System for In-Furnace NOx Reduction** by N. Okigami, Y. Sekiguchi, Y. Miura, K. Sasaki and B. Tamaru, Proceedings of the 1985 Joint Symposium on Stationary Combustion NOx Control, 1986.
- **Three Stage Combustion (Reburning) on a Full Scale Operating Boiler in the USSR** by R.C. LaFlesh, R.D. Lewis and D.K. Anderson of Combustion Engineering, Robert E. Hall of US EPA, and V.R. Kotler of All Union Heat Engineering Institute (VTI), Moscow, USSR, Presented at the Joint EPA/EPRI Symposium on Stationary Combustion NOX Control, 1991.
- **Comparisons of Micronized Coal, Pulverized Coal and No. 6 Oil for Gas/Oil Utility and Industrial Boiler Firing** by E.T. Robinson of Advanced Fuels Technology Company, Oliver G. Briggs, Jr. of Riley Stoker Corporation, and Robert Bessette of IES, presented at the American Power Conference, 1988.
- **Reburn Technology for NOx Control on a Cyclone-Fired Boiler** by R.C. Booth of Energy Systems Associates, R.E. Hall of US EPA, R.A. Lott of GRI, A. Kokkinos of EPRI, D.F. Gyorke of DOE-PETC, S. Durrani of Ohio Edison, H.J. Johnson of OCDO, J.J. Kienle of East Ohio Gas; R.W. Borio, R.D. Lewis, M.B. Keough of ABB Combustion Engineering, Presented at the Joint EPA/EPRI Symposium on Stationary Combustion NOx Control, 1991.

# Integrated Dry $NO_x/SO_2$ Emissions Control System Update

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**ABSTRACT**

Public Service Company of Colorado has recently installed an Integrated Dry $NO_x/SO_2$ Emissions Control System at its 100 MWe Arapahoe 4 steam electric generating station. The work is being completed as part of a U.S. Department of Energy Round III Clean Coal Project. The system combines low-$NO_x$ burners, overfire air, selective non-catalytic reduction (urea injection), dry sorbent injection using either calcium or sodium-based sorbents, and a humidification system to obtain up to a 70% reduction in both $SO_2$ and $NO_x$ emissions.

Baseline testing was completed in December 1991 before the new equipment was added. The urea injection system was installed in December and original urea baseline testing was initiated in February 1992. The urea injection system worked well and $NO_x$ removals of 30% were obtained with ammonia slips less than 5 ppm. The boiler equipment was installed in a 10 week outage that was completed on May 30, 1992. The new low-$NO_x$ burners and overfire air system are operational and preliminary startup testing has shown that $NO_x$ has been reduced from a 1.15 #/MMBtu baseline to approximately 0.40 #/MMBtu. Detailed testing is scheduled to begin in early August 1992 and will continue through mid 1994.

## INTRODUCTION

Denver Colorado is a beautiful city located at the base of the majestic Rocky Mountains but as rapid growth occurred in the 70's and 80's the city has also become known for occasional visible pollution problems. Public Service Company of Colorado (PSCC) became very involved in the late 1980's and began retrofitting Denver area units with new low-$NO_x$ burners and also installed the first commercial U.S. utility sodium-based dry sorbent injection system. However, PSCC has six roof-fired boilers located in the Denver area and could find no commercially proven means to reduce $NO_x$ on these units. In addition, a problem that was limiting wider commercialization of sodium-based injection systems was discovered. Although sodium injection was very efficient for $SO_2$ removal, it also causes a conversion of a small amount of nitrogen oxide (NO) in the flue gas to nitrogen dioxide ($NO_2$). While this did not affect the total pollution removal capabilities of the system it did cause a visible plume to form under certain operating conditions.

After some study it was decided that PSCC would take a leading role in developing the technology to reduce $NO_x$ emissions on this unusual boiler type and also help advance the dry sorbent injection technology at the same time. A proposal was submitted to the U.S. Department of Energy (DOE) in late 1989 to demonstrate a new Integrated $NO_x/SO_2$ Emissions Control System. This new system, consisting of a group of existing but not fully developed technologies, would remove up to 70% of both the $NO_x$ and $SO_2$ emissions. The demonstration would be completed on PSCC's Arapahoe 4 unit located in southwest Denver. Arapahoe 4 is a Babcock & Wilcox (B&W) 100MWe pulverized coal unit that was originally placed in service in 1955.

PSCC first step was to assemble a competent team of professionals to support the engineering and construction of this project. Babcock & Wilcox (B&W) was selected to design, supply and install the low-$NO_x$ burners and overfire air system. Stone & Webster Engineering Corporation provided engineering support for many items through out the project. Noell Inc. provided for the design and supply of the urea injection system while Coastal Chem, Inc will supply the urea used for the testing. Fossil Energy Research

Corporation (FERCO) will organize and implement the test program. The expertise of Western Research Institute will be used to characterize the waste materials generated and the Colorado School of Mines will assist in developing the chemical kinetics of the sodium and urea processes.

Funding for this program is being provided by the DOE, PSCC, and the Electric Power Research Institute (EPRI).

**PROJECT DESCRIPTION**

The Integrated Dry $NO_x/SO_2$ Emissions Control System, also referred to as the Arapahoe 4 Project, consists of five major control technologies that are combined to form an integrated system to control both $NO_x$ and $SO_2$ emissions. Low-$NO_x$ burners, overfire air, and urea injection are used to control $NO_x$ emissions while dry sorbent injection using either sodium or calcium-based reagents is used to control $SO_2$ emissions. Figure 1 shows a simplified schematic of the Integrated $NO_x/SO_2$ Emissions Control System as implemented at Arapahoe.

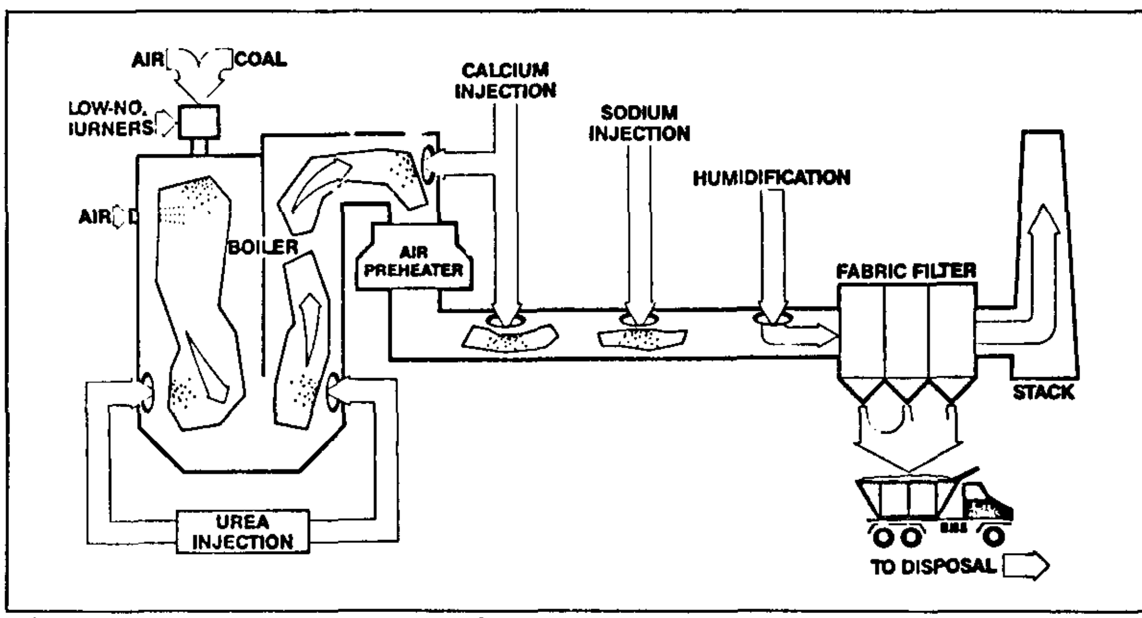


Figure 1 - Process Flow Diagram

The emissions control system has been retrofit to the Arapahoe 4 steam electric generating station located in southwest Denver, Colorado. Arapahoe 4 is a 100MWe roof-fired unit placed in service in 1955. The unit's main fuel is a low sulfur (0.4%) Western bituminous coal but it may also be fired up to full load using natural gas. Roof-fired units similar to Arapahoe are in the minority in the U.S. as only approximately 65 boilers of this type are installed. Figure 2 shows an elevation view of the boiler. Roof-fired units are characterized by a small furnace with a very turbulent flame. $NO_x$ emissions are very high compared to wall and tangentially fired boilers and are in the range of 1.15 #/MMBtu.

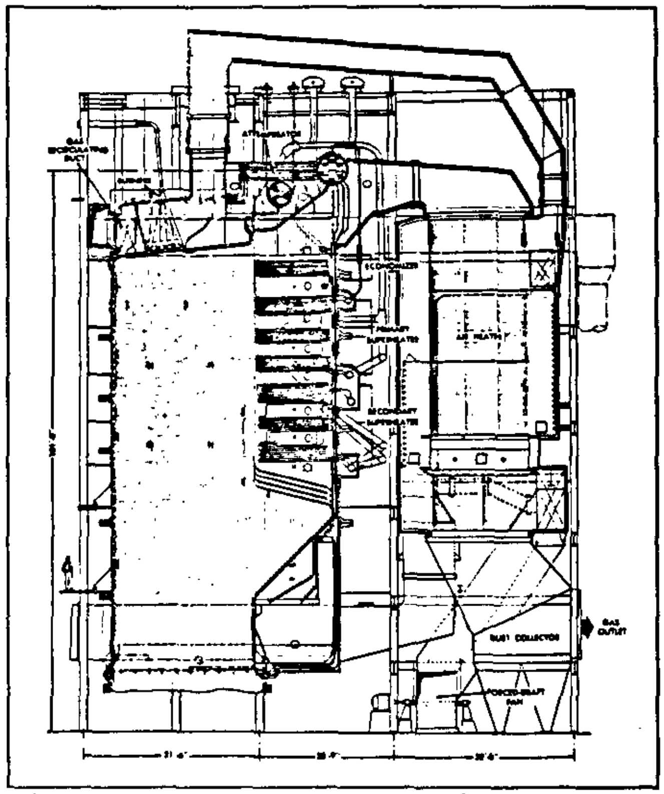

Figure 2 - Arapahoe 4 Boiler

Low-$NO_x$ Burners

To control the amount of $NO_x$ emissions originally formed, B&W DRB-XCL™ burners have been retrofit to the unit. The DRB-XCL™ burner has been successfully retrofit to wall fired boilers, but this is the first application of the burner in a vertical position. As shown in figure 3 a sliding damper is used to control the total air flow to each burner. The major modification made to the DRB-XCL™ burner for

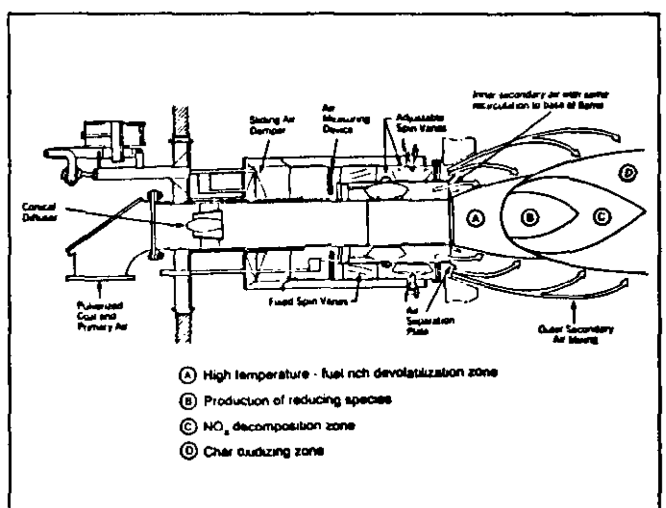


Figure 3 - B&W DRB-XCL™ Burner

vertical firing is a design change to the linkage that moves the sliding damper. The modification is required due to the greater forces involved in vertical movement. The secondary air then passes through either the inner or outer spin vanes. These dual spin vanes allow independent adjustment of the rate at which air is mixed with the coal. A pitot tube grid is contained in the secondary air stream so that an indication of the total air flow is available to each burner.

The low-$NO_x$ retrofit at Arapahoe was much more involved than modifications to most wall or tangential fired units. The original system contained twelve intertube burners. Each of the original burners split into 20 individual coal jets. Thus there were no original openings in the boiler roof to accommodate a "normal" burner. The modifications began by removing everything from the boiler roof tubes to the roof of the boiler enclosure including the windbox roof, coal and gas piping, and even the secondary air supply duct. The installation was complicated by the extensive amount of asbestos insulation used in the original boiler. The twelve new burners were located in 4 rows of 3 burners. Due to the very tight fit of the new burners and the limited space available for the main secondary air duct, it was decided to use the abandoned gas recirculation duct as an additional source of secondary air to the windbox. The retrofit also included new gas burners, gas ignitors, and flame scanners. No modification were made to the original Riley pulverizers although a new feeder drive was added to provide more consistent coal feed.

The goal of the low-$NO_x$ burner system at Arapahoe is to provide up to a 50% $NO_x$ reduction.

Overfire Air

To provide even more $NO_x$ reduction than is possible with low-$NO_x$ burners alone, an overfire air system or in this case an "underfire" air system was also retrofit to the Arapahoe unit. The system can direct up to 25% of the total secondary air below the main combustion zone. This allows the main combustion to occur with below stoichiometric air conditions which greatly minimizes the amount of $NO_x$ formed. Three B&W Dual Zone $NO_x$ Ports were added to each side of the furnace approximately 20 feet below the boiler roof. The $NO_x$ ports separate the overfire air into two streams. The center air is injected at high velocity into the furnace with sufficient momentum to reach the center division wall and the inner air is spread with adjustable spin vanes to distribute the air near the wall. Two pitot tube grids are used so that the relative air flow between the two areas may be balanced.

The goal of the overfire air system at Arapahoe is to provide up to a 20% $NO_x$ reduction from the original baseline. Thus the entire combustion modification is hoped to provide up to a 70% $NO_x$ reduction.

Selective Non-Catalytic Reduction

After obtaining the maximum $NO_x$ reduction possible with combustion modification, further $NO_x$ reduction is obtained with a urea based selective non-catalytic reduction (SNCR) system. Urea injection is not new and has been demonstrated on gas fired boilers, although Arapahoe 4 is believed to be the first full scale demonstration on a U.S. utility coal fired unit. A liquid solution of urea is injected into the boiler. When the urea decomposes at approximately 1700 to 1900°F, $NO_x$ is converted to nitrogen and water. The disadvantage of urea injection is that it is very temperature sensitive. If the temperature is to high, some of the urea can actually be converted to $NO_x$. If the temperature is to low, more of the urea is converted to ammonia which creates an unacceptable new pollutant.

Noell, Inc was selected to design and supply the urea based SNCR system at Arapahoe. Figure 4 contains a simplified flow diagram of the system as implemented at Arapahoe. Urea is received in a 65% liquid urea solution and stored in one of two 20,000 gallon storage tanks. As the concentrated urea solution will freeze at approximately 115°F, the solution is continually circulated through an electric heater system. A small slipstream of the urea is filtered, mixed with softened water to further dilute the urea, and is then pumped at high pressure (300 to 600 psig) to Noell's proprietary injection nozzles. A centrifugal compressor is used to supply a large volume of medium pressure (6 to 12 psig)

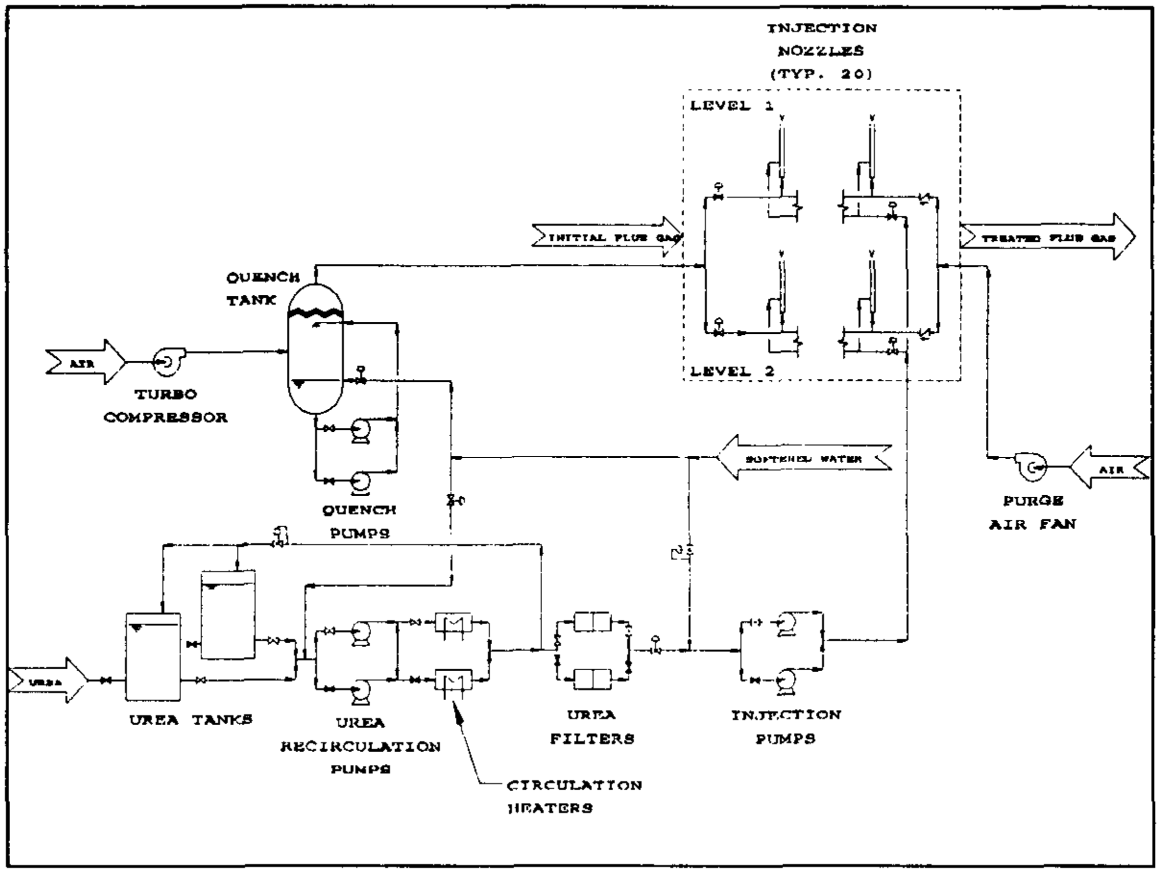


**Figure 4 - Urea Flow Diagram**

air at the injection nozzles to help atomize the urea solution and rapidly mix the urea with the flue gas. Arapahoe has two levels of ten injectors located in the convective section of the boiler. Each level of nozzles enters the boiler in a different temperature range so that some temperature control of the injection system is available.

While SNCR provides the advantage of a simpler and lower cost system than the competing Selective Catalytic Reduction system, it has the disadvantage of lower $NO_x$ removals and also the potential for higher ammonia slips. The goal at Arapahoe is to provide up to a 40% $NO_x$ reduction from the reduced levels obtained with the combustion modification.

Dry Sorbent Injection

Sulfur dioxide emissions will be controlled at the Arapahoe 4 unit by using two different types of dry sorbent injection. Dry sorbent injection is a low capital cost alternative for $SO_2$

reduction that is based on very simple concepts. A very fine reagent such as sodium sesquicarbonate ($NaHCO_3 \bullet Na_2CO_3 \bullet 2H_2O$) or sodium bicarbonate ($2NaHCO_3$) is evenly distributed in the flue gas before the particulate control device. The $SO_2$ will combine with the sodium product and form sodium sulfate particulate per the following reaction:

$$2NaHCO_3 \dashrightarrow Na_2CO_3 + H_2O + CO_2$$
$$Na_2CO_3 + SO_2 + 1/2O_2 \dashrightarrow Na_2SO_4 + CO_2$$

This sulfate particulate is then captured in the fabric filter dust collector and is disposed of with the fly ash. While sodium has been demonstrated to provide high $SO_2$ removal rates at very good utilizations, it does have one major system flaw. During the $SO_2$ removal reaction, a small portion of the NO is converted into $NO_2$ through a little understood chemical reaction. Although this does not increase the net $NO_x$ emissions from the unit it can create a visibility problem as $NO_2$ is a red-brown colored gas while NO is a colorless gas. Very small amounts of $NO_2$ in the range of 10 to 30 ppm, depending on background conditions and stack size, can create a visibility problem on the unit. [1]

The Electric Power Research Institute (EPRI) has found that if the $SO_2$ removal reaction occurs in the presence of small amounts of ammonia base compounds, the visible $NO_2$ plume can be greatly reduced or even eliminated. [2] A major point that will be demonstrated at Arapahoe is the synergistic effect that will occur by performing urea injection into the boiler and sodium injection into the duct. The urea injection will reduce $NO_x$ and will also generate a small amount of NH3 slip. In most cases this is a major deficiency of urea injection but at Arapahoe the ammonia slip will be used in the sodium injection system in order to control the amount of $NO_2$ conversion. At Arapahoe, sodium injection and urea injection will be combined and the disadvantages of both systems will be greatly reduced. This technology has not been demonstrated at full scale however, a U.S. patent has been applied for this technology.

Figure 5 shows a flow diagram of the dry injection system installed at Arapahoe. Reagent is delivered by truck and is stored in one of two 150 ton silos. The material is then fed from

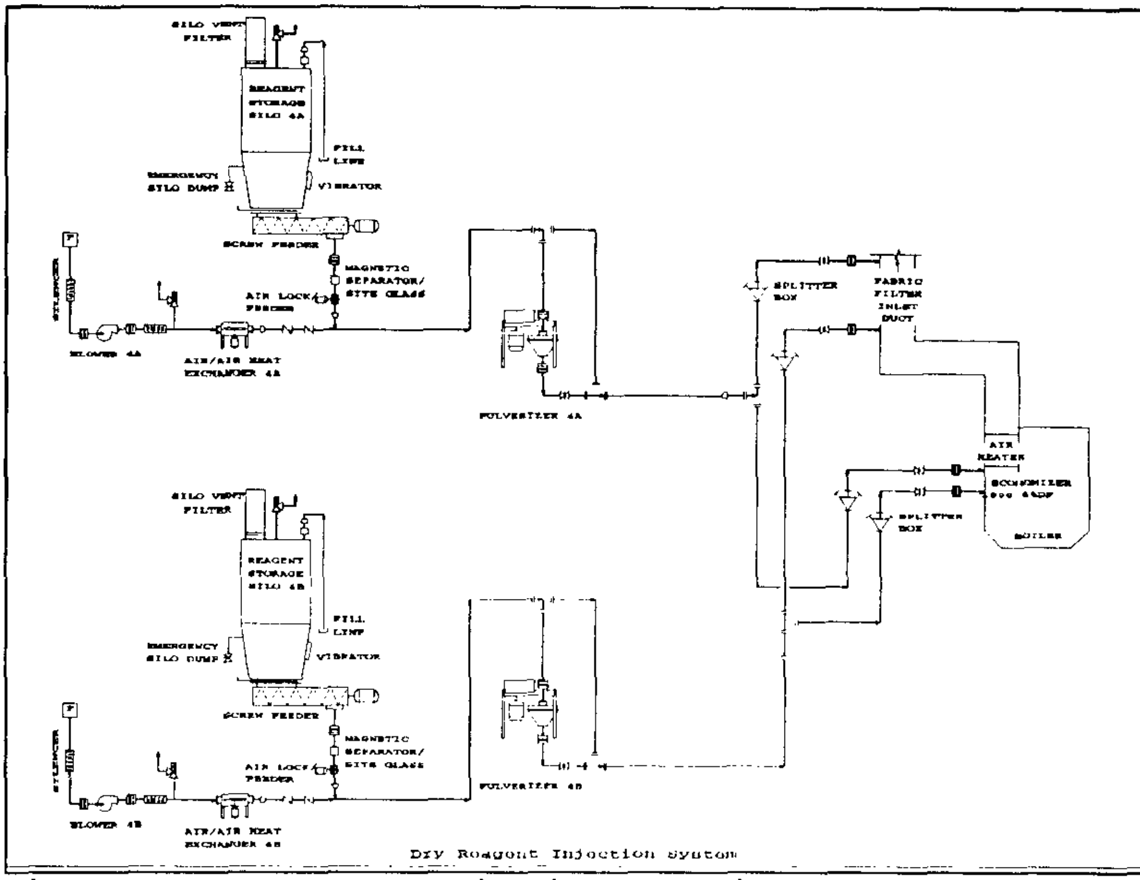


**Figure 5 - Dry Sorbent Injection Flow Diagram**

a volumetric screw feeder into a dilute phase pneumatic system and is carried to the pulverizer where the material is ground to approximately 90% -400 U.S. Standard mesh. The freshly ground material then travels to the duct where the injection system evenly distributes the material in the flue gas. The expected $SO_2$ reduction at Arapahoe using sodium sorbent injection before the fabric filter is 70%.

Calcium hydroxide ($Ca(OH)_2$) reagent has been successfully demonstrated as a reagent for $SO_2$ removals.[3] Calcium reagent at low temperatures does obtain some $SO_2$ removal but utilization of calcium-based reagents is significantly lower than the sodium-based reagent. Humidification has been used to greatly increase the efficiency of the process and a B&W supplied system will also be used at Arapahoe in order to increase the $SO_2$ removal. At Arapahoe, calcium hydroxide will be injected into the low temperature range (300°F) in the duct similar to the sodium injection. Due to the very fine particle size of calcium hydroxide, it will not be pulverized. The goal using calcium reagent injection and the humidification system is for up to 50% $SO_2$ removal.

In order to obtain higher removals using calcium, calcium hydroxide will also be injected into a 1000°F range in the convective pass of the boiler. At this temperature laboratory testing has shown that a peak occurs in the calcium reaction so that higher $SO_2$ removal will be possible.[4] The humidification system will also be used with the high temperature calcium injection as a means to increase $SO_2$ removal and calcium utilization. It is hoped to achieve up to 70% $SO_2$ removal using the high temperature injection and humidification.

Balance of Plant

Various other modifications were required throughout the plant due to the Integrated Dry $NO_x/SO_2$ Emissions Control system. One major change to the plant was the addition of a new Distributed Control System. The major modifications required to the boiler required the addition of a burner management system. The existing 1950's vintage pneumatic control system was not capable of controlling the major additions to the boiler and the integration of a flame scanner system.

The addition of the dry reagent injection system will significantly change the characteristics of the ash due to the addition of soluble compounds to the fly ash. The original ash system at Arapahoe used a wet sluice system that collected ash in on-site ponds. The ponds were periodically dredged and the ash disposed of at an off-site disposal site. A new dry ash collection system was installed as part of the project to ensure the ash was handled and disposed of properly.

A Continuous Emissions Monitoring (CEM) system was added at Arapahoe 4 to collect data for the test program. The system is fairly complex due to the continuous measurement of $N_2O$, $NH_3$, and, $NO_2$ in addition to the more common pollutant measurements. The percentage of water in the flue gas will also be directly measured to determine the effectiveness of the humidification system.

## PRELIMINARY RESULTS

We have just entered Phase III testing and have begun the process of detailed testing of the Integrated Dry $NO_x/SO_2$ Emissions Control System but two series of testing have been completed. A baseline test was conducted on the unit to determine the emissions before any modifications were completed. A short test was also conducted with the urea injection system under the high $NO_x$ conditions using the original burners.

### Baseline Testing

A complete series of tests was conducted at Arapahoe before any of the planned modifications were installed. A series of parametric tests were completed to determine the effect of various operating parameters on $NO_x$ emissions. The only variable that had a significant effect on $NO_x$ was excess oxygen. The $O_2$ effect was generally linear. A 1% change in oxygen would cause a 145 ppm change in baseline $NO_x$. Figure 6 shows the baseline emissions. Note that across the load range, $NO_x$ emissions are fairly flat at approximately 800 ppm (3% $O_2$,dry). $SO_2$ emissions are a direct function of the coal used. Arapahoe uses a low sulfur (0.4%) Western coal and $SO_2$ emissions are approximately 400 ppm with no load effect as expected. Carbon monoxide emissions can be controlled fairly easily and are under 50 ppm for most operating conditions. Fly ash carbon samples were obtained for many of the tested conditions and are in the range of 3 to 5%.

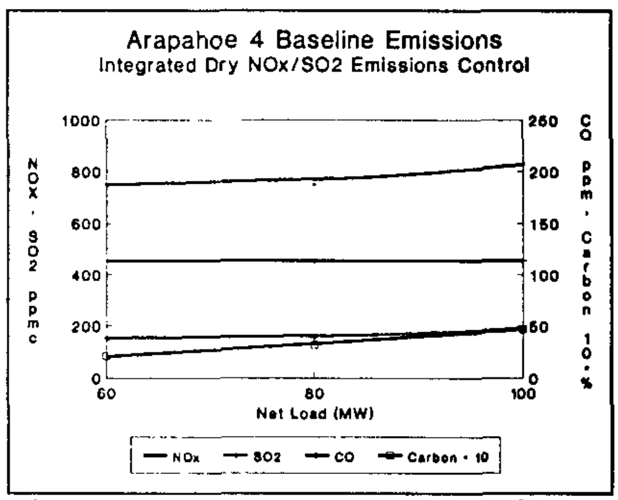


**Figure 6 - Arapahoe 4 Baseline**

Selective Non-Catalytic Reduction Testing

Initial testing of the urea injection system began in February 1992. At full load the system worked quite well and $NO_x$ removal levels of approximately 30% were obtained with 5 ppm ammonia slip as shown in Figure 7. Higher $NO_x$ removal levels could be obtained but at the cost of higher ammonia slip. As the load was reduced, the temperatures at the point of injection also reduced. At lower temperatures more of the urea converts to NH3 in an area of boiler that is too cold for effective $NO_x$ reduction. Figure 8 shows the removals that were possible at 60MWe. At this load only approximately 10% $NO_x$ removal could be obtained with minimal ammonia slips. At full load the temperature at the point of injection was approximately 2060°F and at 60MWe the temperature reduced to approximately 1800°F based upon testing conducted with an acoustic pyrometer at the hottest injection location. At the cooler injection location, flue gas temperatures decreased by approximately 100°F.

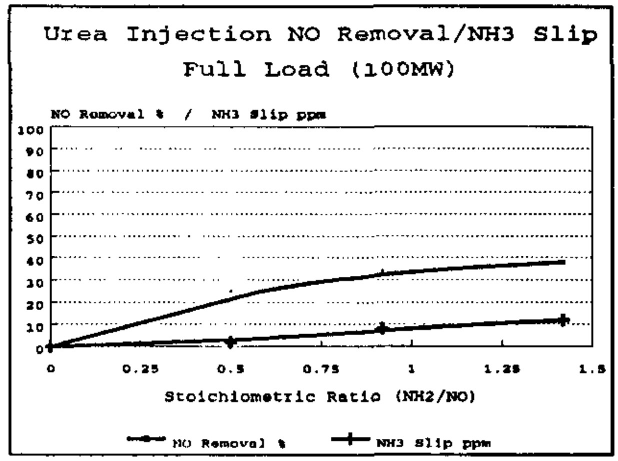

Figure 7 - Urea Injection 100MW

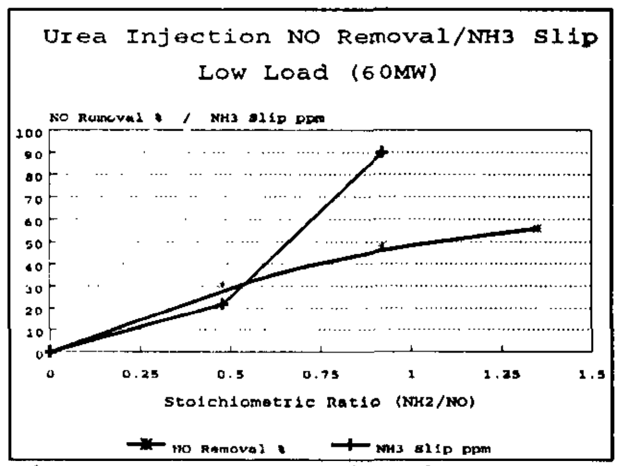

Figure 8 - Urea Injection 60MW

The total amount of fluid injected is a very important variable to optimize in urea injection. The original system at Arapahoe was designed to inject 28 gpm of fluid. During the startup period it was found that the temperatures at the point of injection were 100 to 150°F lower than originally expected. Even though the hottest level of injection was used at the 28 gpm fluid injection rate, the flue gas temperature was too low for effective $NO_x$ removal at minimum ammonia slip. The fluids injection rate at Arapahoe was decreased to approximately 7 gpm. With less localized cooling due to evaporation, the effective urea injection temperature was raised and the ammonia slip was substantially reduced. This increase in effective injection temperature also lowered the $NO_x$ reduction. Lowering the fluids injection rate has the added benefit of reducing the boiler efficiency penalty of urea injection.

A major disadvantage of urea injection is that not all NO reduction is a conversion to nitrogen and water. A portion of the nitrogen oxide reduction is actually a conversion to nitrous oxide ($N_2O$). A continuous emission monitor was used to measure the amount of $N_2O$ generation during the baseline testing of the SNCR system at Arapahoe. Figure 9 shows the data collected on $N_2O$ generation at both 60 and 100MWe. Approximately 10 to 15% of the NO reduction is shown to actually be a conversion to $N_2O$.

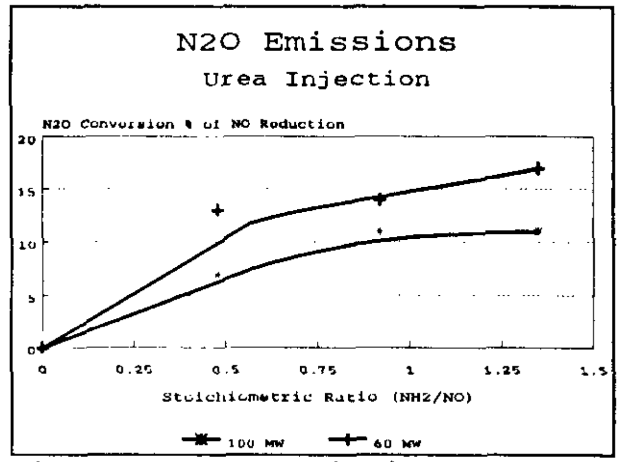

Figure 9 - N2O Emissions/Urea

Due to the lower than expected flue gas temperatures experienced at low load, it was decided to perform a short test using liquid ammonium hydroxide ($NH_4OH$). It was projected that the ammonium hydroxide would react faster and thus would provide less ammonia slip than urea at the lower temperatures. The ammonia was injected into the boiler in the same location as the urea but the ammonium hydroxide was stored and pumped through a temporary system. The data in figure 10 shows that ammonium hydroxide was more effective at low load and a removal rate of nearly 30%

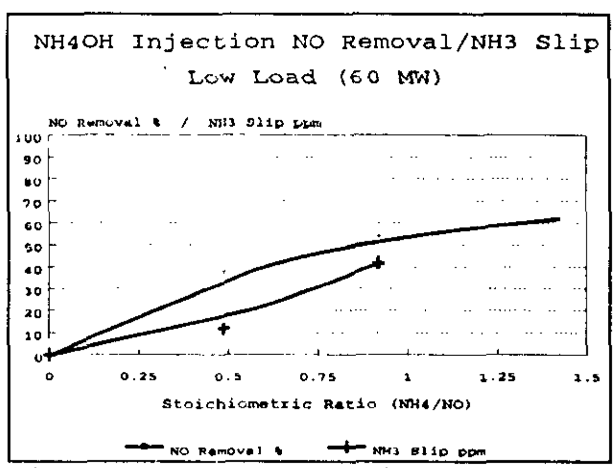

Figure 10 - $NH_4OH$ Injection 60MW

was possible with minimal ammonia slip. Another advantage of the ammonium hydroxide reagent is that the conversion of NO to $N_2O$ is much lower as shown in figure 11. This testing does confirm that ammonium hydroxide reacts faster than urea, but insufficient time was available to optimize the system using this reagent.

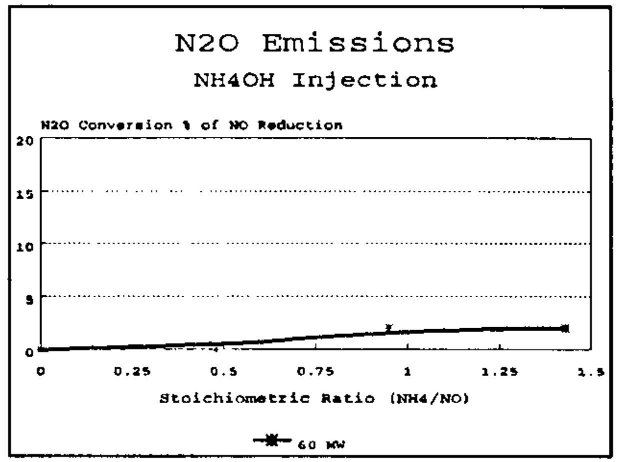

**Figure 11 - $N_2O$ Generation/$NH_4OH$**

Future work planned for the urea injection system includes optimization of the system with the low-$NO_x$ conditions that are expected after the new combustion system has been tested. The new burners and overfire air may change the temperatures in the convective pass and it is also hoped that a better temperature balance can be obtained with the new burners. A system that can convert urea on-line into ammonium hydroxide is also being investigated as a design modification of the system. This would allow testing of both chemicals to determine the most effective reagent.

Low-$NO_x$ Burners and Overfire Air

The installation of the low-$NO_x$ burners proceeded very well during the construction phase of the project. Only minor problems occurred during startup. One of the burner sliding dampers bound up during initial operation but construction crews were able to free the disc with the unit operating. It was found that carbon carryover to the fabric filter was much greater than expected. After the system was tuned and the spin vanes properly adjusted, carbon carryover decreased to the original baseline levels. Testing is currently in progress on the low-$NO_x$ burners and overfire air system but preliminary testing completed during tuning using the recently installed continuous emission monitor indicates that $NO_x$ has been reduced to approximately 0.4 #/MMBtu from the original baseline of 1.15 #/MMBtu. These is very preliminary data and further testing will be required to document the $NO_x$ reduction and also determine carbon loss for the new burners.

## PROJECT SCHEDULE

Engineering and procurement activities began immediately after the signing of the Cooperative Agreement in March of 1991. Construction began in late July 1991 and the urea injection system was completed in late December. Construction of the boiler modifications began in January 1992 and these were completed slightly ahead of schedule on May 30, 1992. The boiler is now operating with the new burners and the overfire air system.

Phase III operations and testing began in late July with original emphasis on documenting performance of the low-$NO_x$ burners and overfire air. In November of 1992 the urea injection system will be tested with the low-$NO_x$ conditions generated by the newly installed burners and overfire air. Calcium injection testing will follow in February 1993 and sodium injection testing will begin in June of 1993. After each of the systems has been fully tested individually, the most efficient control methods will be tested in an integrated system. The demonstration will be completed by testing a high sulfur (2.5%) coal with the system for up to one month. In addition to the main emissions testing planned over the next two years, a complete baseline of up to twenty-three possible air toxics will be completed as part of this program. Smaller scale testing of air toxics will also be conducted with both the dry injection and urea injection systems to determine what effect these systems will have on air toxics.

## SUMMARY

Public Service Company of Colorado, in cooperation with the U.S. Department of Energy and the Electric Research Power Institute, has installed and is beginning to test a new system for $NO_x$ and $SO_2$ emissions control. The Integrated Dry $NO_x/SO_2$ Emission Control System consists of low-$NO_x$ burners, overfire air, selective non-catalytic reduction (urea injection), and dry sorbent injection using either calcium or sodium-based reagents. This system is lower in capital cost and is more easily retrofit to older units than some competing technologies.

The system was installed on schedule and the new DRB-XCL™ burners are operating very well. Baseline testing of the unit has shown that $NO_x$ emissions are in the range of 1.15#/MMBtu at Arapahoe. Initial baseline testing of the urea injection system has been completed and $NO_x$ reduction of approximately 30% is possible with ammonia slips of 5 ppm at full load. Approximately 15% of this NO reduction is a conversion to $N_2O$. Future testing will document the burner performance and also the urea injection system at the lower $NO_x$ conditions that exist with the new burners. Dry sorbent injection system will then be tested using both calcium and sodium-based reagents. After testing of the individual emissions control systems, the optimum integrated system configuration will be tested with both low and high sulfur coal. The testing phase will be completed in mid 1994 and a final report is expected in late 1994.

## ACKNOWLEDGEMENTS

A project of this size and complexity can not be completed with cooperation from many different parties. The authors would like to thank Mr. Thomas W. Arrigoni and Mr. Dave Hunter from the DOE for their help through the contract and construction phases of this project. The services of FERCO and Noell were of great benefit during the two testing phases that have been completed to date. Many people at EPRI have contributed both time and information that have helped with the success of this project. Finally without excellent cooperation with the plant operations and maintenance personnel managed by Mr. George Brown, the project would not be on schedule.

(b) Assumes any liabilities with respect to the use of, or for damages resulting from the use of, any information, apparatus, method or process disclosed in this report.

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# SESSION 8:
# Retrofit for $SO_2$ Control

*Chairs: Dr. John A. Ruether, DOE PETC*
*Stewart J. Clayton, DOE Headquarters*

# Update and Results of Bechtel's Confined Zone Dispersion (CZD) Process Demonstration at Pennsylvania Electric Company's Seward Station

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**Allen G. Rubin**
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**Project Manager**

**DOE's Pittsburgh Energy Technology Center**

## ABSTRACT

The U.S. Department of Energy and Bechtel Corporation are engaged in a joint project to demonstrate Bechtel's Confined Zone Dispersion (CZD) technology. The demonstration is being conducted at Pennsylvania Electric Company's (Penelec's) Seward Station, on Unit No. 15. This boiler is a 147 MW coal-fired unit, which utilizes Pennsylvania bituminous coal (approximately 1.2 to 2.5 percent sulfur). One of the two flue gas ducts representing one half of the boiler's flue gas capacity has been lengthened and retrofitted with the CZD technology. A new long straight duct has replaced the original multi-bend duct to ensure a residence time of about 2 seconds. The goal of this demonstration is to prove the technical and economic feasibility of CZD technology on a commercial scale. The process is expected to achieve 50 percent sulfur dioxide ($SO_2$) removal at lower capital and operations and maintenance (O&M) costs than other systems.

The CZD process involves injecting a finely atomized slurry of reactive lime into the flue gas duct work of a coal-fired utility boiler. The principle of the confined zone is to form a wet zone of slurry droplets in the middle of the duct confined in an envelope of hot gas between the wet zone and the duct walls. The lime slurry reacts with part of the $SO_2$ in the gas, and the reaction products dry to form solid particles. A solids collector, typically an electrostatic precipitator (ESP), downstream from the point of injection captures the reaction products, along with the fly ash entrained in the flue gas.

The current test program is being conducted in two parts. The first part, parametric testing, started in July 1991 and was completed in August 1992. During this period, the objectives were as follows:

- To carry out a factorial test program that allowed optimization of the performance of the CZD process and development of operating conditions that achieve high reliability and low-cost operation

- To perform design, procurement, installation, and facility construction to provide a fully instrumented and automated CZD system, fully integrated with the operation of Penelec's Unit No. 15
- To debug the new automated system so that it operates from the power plant control room for continuous CZD operation (24 hours/day and 7 days/week)

The second part, from August 1992 to February 1993, will complete this demonstration project. The goal is to demonstrate the performance of the CZD process for $SO_2$ removal without significantly affecting either boiler operation or plant particulate emission. Penelec will operate the CZD system as a normal part of Unit No. 15. Bechtel will supervise the 6-month continuous demonstration and will carry out various performance tests, data acquisition, and chemical analysis.

The demonstration is expected to confirm earlier economic projections. The CZD process is projected to cost less than $300/ton of $SO_2$ removed. Based on a 500 MW plant retrofitted with CZD for a 50 percent $SO_2$ removal, the total capital cost is estimated at less than $25/kW. The cost includes lime unloading, lime handling, and the fully automated operation. The variable operating cost for this retrofit is estimated at less than 3.0 mills/kWh.

## INTRODUCTION

The CZD process involves flue gas post-treatment, physically located between the boiler outlet and the particulate collector, which in most of cases is an ESP.

The features that distinguish the Bechtel CZD process from other similar injection processes are the following:

- Injection of an alkaline slurry directly into the duct. Other processes use injection into a conventional spray-dryer vessel or injection of dry solids into the duct ahead of a fabric filter.
- Use of an ultrafine calcium/magnesium hydroxide, Type S pressure-hydrated dolomitic lime. This commercial product is made from plentiful, naturally occurring dolomite.
- Low residence time made possible by the high effective surface area of the Type S lime.
- Localized dispersion of the reagent. Slurry droplets contact only part of the gas while the droplets are drying, to remove up to 50 percent of the $SO_2$. The process uses dual fluid rather than rotary atomizers.
- Improved ESP performance via gas conditioning from the increased water vapor content and lower temperatures. As a result, supplemental conditioning with $SO_2$ is not necessary for satisfactory removal of particulate matter.

The waste product is composed of magnesium, calcium sulfites, and sulfate, with excess lime and fly ash. The waste fly ash mixture usually has pozzolanic properties.

The mixture is self-stabilizing because of the excess lime and tends to retain heavy metals in insoluble forms within the fly ash. Laboratory tests have shown that the waste solids can be pelletized.

## CZD-FLUE GAS DESULFURIZATION (FGD) DEMONSTRATION AS PART OF DOE'S CLEAN COAL TECHNOLOGY DEMONSTRATION PROGRAM

The U.S. Department of Energy and Bechtel Corporation have agreed to a cooperative effort to demonstrate the Bechtel-developed CZD technology at Pennsylvania Electric Company's Seward Station. DOE is providing half, or $5.2 million, of the project's total $10.4 million cost. Others contributing to the project are Pennsylvania Electric Company ($3 million), Bechtel ($1.3 million), the Pennsylvania Energy Development Authority ($750,000), New York Gas and Electric Company ($100,000), and Rockwell Lime Company ($13,000). Pennsylvania Electric Company is providing the project's demonstration test site, Seward Station.

The current CZD activities at Seward Station are directed toward demonstrating the best possible atomization and dispersion of the $SO_2$ absorbing slurry in flue gas and the performance of the existing precipitator to handle the increased dust load without adverse effects on the stack gas opacity.

The CZD project at Seward Station includes replacement of the original flue gas duct (35-foot-long segments connected with 45° elbows and corresponding turning vanes) with one new 110 ft long straight duct ahead of the ESP.

The test program consists of two distinct periods:

- In the first period, daily factorial runs were conducted to test different atomizers, limes, and slurry concentrations. First period results will be used to set and optimize second period operations.
- In the second period, the performance of a continuously running CZD system is being demonstrated under the actual power plant operating conditions. The CZD demonstration will be integrated into one half of the flue gas capacity of the commercial unit (147 MW) for six months operating in three shifts, 7 days/week.

## PURPOSE OF THE TEST PROGRAM

The primary objectives of the project are to:

- Achieve SO2 removal of 50 percent,
- realize $SO_2$ removal costs of below $300/ton, and
- eliminate negative effects on normal boiler operation without increasing particulate emissions and opacity.

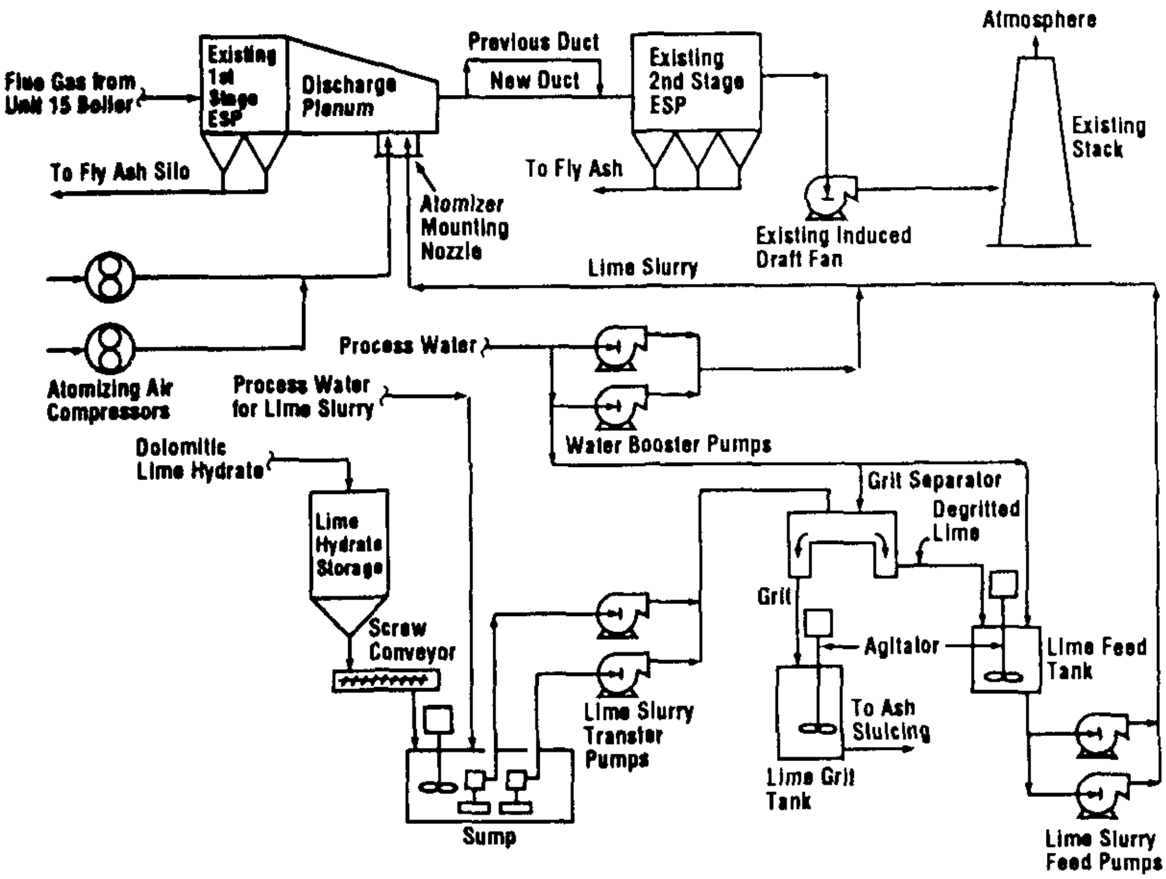


**Figure 1 Seward Station Overall Process Flow Diagram**

The CZD process as shown in Figure 1 has been automated and integrated with only one of the two existing modules of air preheater/flue gas duct/ESP and induced draft fan associated with Unit No. 15. All auxiliary subsystems, such as lime slurrying, degritting, and lime slurry handling, have also been automated.

The demonstration project will permit optimization of the system for application at different locations by determining the:

- Degree of atomization (slurry/compressed air ratio) versus length of duct required for evaporation of atomized slurry,
- maximum volume of slurry that can be injected per square foot of duct cross section and the confined zone dimensions of the duct cross section that will prevent deposits on duct surfaces, and
- effect of flue gas inlet temperature on the evaporation characteristics, $SO_2$ removal, and alkali utilization.

Other objectives of the demonstration project will include:

- Performing comparison tests of hydrated calcitic lime and freshly slaked calcitic lime.
- Testing methods for improving ESP performance during lime injection:
  - Monitoring ESP operating and opacity variations during all injection tests.
  - Performing particulate emission measurements on several extended runs.
  - Investigating methods to improve ESP performance, if necessary.
- Testing different slurry atomizers to determine the most energy-efficient and erosion-resistant.
- Testing selected additives for improving $SO_2$ and nitrous oxides ($NO_x$) removal.
- Testing the effect of burning higher sulfur coal on $SO_2$ /$NO_x$ percent removal.

## DESCRIPTION OF THE CZD PROCESS

The spray of lime slurry is injected close to the center of the flue gas duct parallel to the flow of gas, as shown in Figure 2. As a cone of spray moves downstream and expands, the gas within the cone cools and its $SO_2$ is rapidly absorbed by the liquid droplets.

Spray droplets on the outside of the cone mix with hot gas and dry very rapidly. With the proper choice of slurry concentration and injection rate, drying will be complete before droplets contact the walls of the duct. The process does require a sufficient length of straight duct downstream from the sprays, estimated at 60 to 100 feet, and gas flow must be reasonably uniform where the spray is injected. Judicious use of

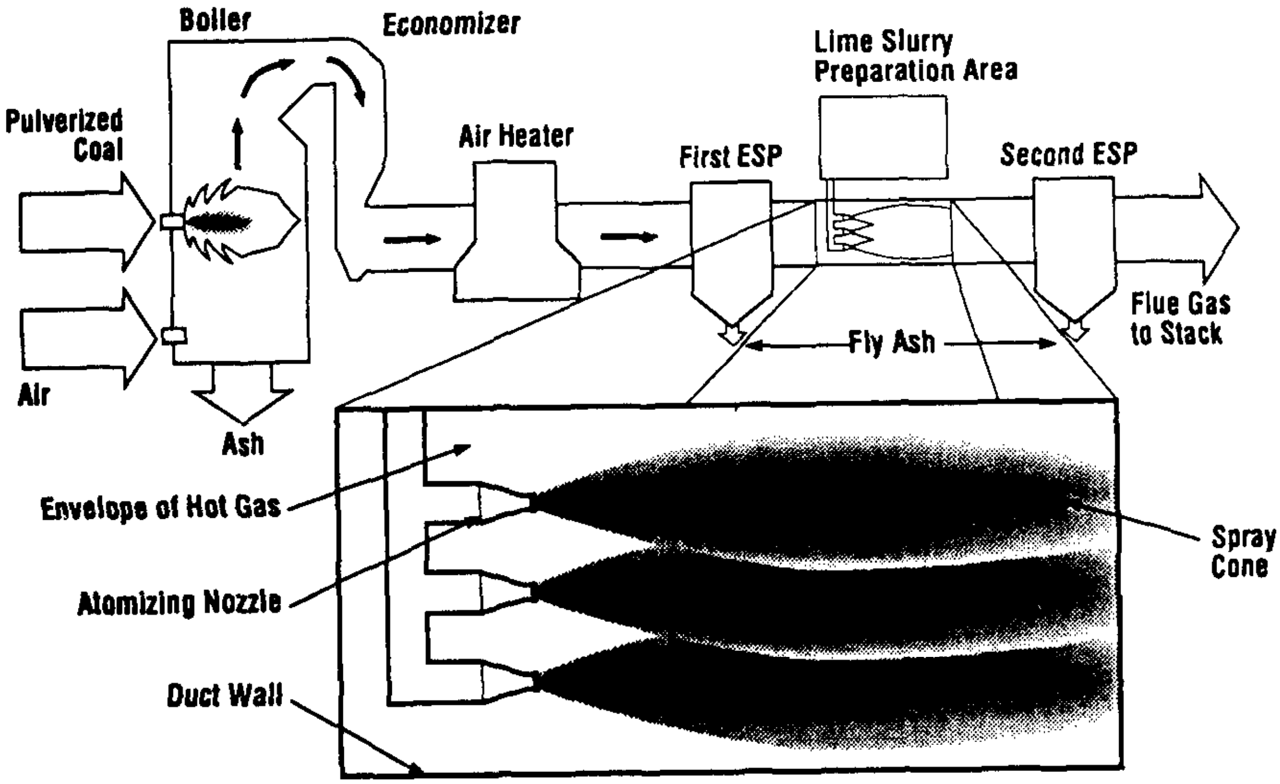


Figure 2 The Confined Zone Dispersion FGD Process

turning vanes, typically installed to minimize pressure drop, makes the gas flow in bends more uniform.

By carefully positioning lime slurry atomizers, it is possible to obtain a wet zone in the middle of the duct with an envelope of hot gas between the wet zone and the duct walls. This is the principle of the confined zone as depicted in Figure 2.

Gas velocity in large ducts is generally about 60 fps at full load, and the flow is highly turbulent. Thus, spray droplets in the expanding cone will be transported outward by eddy diffusion. However, since the outward cone diffusing droplets continuously contact hot gas at about 300°F, they rapidly achieve surface dryness. Exposed to the highly localized full concentration of $SO_2$, the lime reacts extremely rapidly.

The increased mixing associated with turbulent flow also causes hot gas surrounding the cone of spray to be transported inward and to evaporate droplets on the inside of the cone. At a certain point downstream, the free moisture in the spray will have evaporated completely, and the dry solids remaining can contact surfaces of the duct or the turning vanes without adhering and causing deposits to accumulate.

For removal of 50 percent of the $SO_2$ from flue gas with a slurry of pressurized hydrated dolomitic lime (PHDL), slurry concentration is a major variable. Enough slurry must be added to achieve the desired results. A more concentrated slurry will dry more rapidly and allow less time for the slurry to impinge on duct surfaces; on the other hand, it will also allow less time for the lime to react. The demonstration program will provide an opportunity to explore and optimize the control of this variable.

Besides using the reactive PHDL, this CZD process differs in several significant ways from FGD with spray dryers. In a normal spray dryer, a hot gas and slurry are mixed as rapidly as possible in a large vessel. This also serves to mix cooled gas, from which the $SO_2$ has been absorbed, with hot incoming gas having a relatively high concentration of $SO_2$. Thus, the driving potential for $SO_2$ absorption is less than is the case with CZD, where the cone of spray droplets is surrounded by an envelope of unreacted gas. Another difference is that normal spray drying seeks to remove a high percentage of the $SO_2$ and uses a considerable amount of lime. This requires a concentrated slurry (as high as 45 percent solids), which is harder to atomize, forms larger droplets, and is apt to be more abrasive, thus rapidly eroding the atomizers. Erosion of the atomizers is particularly serious when solids containing abrasive fly ash are recycled. In contrast, the CZD process is intended to remove only part of the $SO_2$ and uses less lime than is required to react with all the $SO_2$. The excess of $SO_2$ tends to utilize more of the lime and makes it react faster than it would otherwise. However, the amount of lime is proportional to the amount of $SO_2$ removed.

The chemical mechanism for the absorption of $SO_2$ from the flue gas is simple and very well known. In the presence of water, $SO_2$ from the flue gas is absorbed as sulfurous acid:

$$SO_2 + H_2O \rightarrow H_2SO_3$$

In the presence of water, pressure hydrated dolomitic lime reacts instantaneously with $H_2SO_3$, producing calcium and magnesium sulfites and sulfates:

$$Ca(OH)_2 \cdot Mg(OH)_2 + 2H_2SO_3 \rightarrow CaSO_3 + MgSO_3 + 4H_2O$$

$$CaSO_3 + 1/2O_2 \rightarrow CaSO_4$$

$$MgSO_3 + 1/2O_2 \rightarrow MgSO_4$$

## PAST CZD EXPERIENCE

Over the last few years, considerable testing of the CZD technology was performed as proof-of-concept on pilot and commercial units. References 2, 3, 4, and 5 describe the test programs and the test results of the earlier work.

## OVERALL SYSTEM DESCRIPTION

Figure 1 shows a simplified, overall flow diagram of the Seward CZD system and of the Boiler No. 15 flue gas system. The two systems are closely linked. The boiler has twin air and flue gas systems, designated "A" and "B." The CZD system removes $SO_2$ from the B flue gas stream.

The overall CZD system includes the following process operations and supporting functions:

- FGD duct (flue gas desulfurization section)
- Lime slurry injection
- Lime slurry feed
- Lime slurry preparation
- Atomizing air compression

Figure 2 depicts the interrelation between individual process operations and supporting functions.

### Flue Gas Desulfurization Section

Seward Boiler No. 15 is a balanced draft boiler provided with two F.D. fans, two Ljungstrom air heaters, two twin-chamber ESPs, and two I.D. fans. The two ESPs are joined by twin flue gas ducts that form twin flue gas treating trains, referred to as A and B trains.

Figure 3 presents a plan view of the ESPs and flue gas ducting, with old duct B replaced by the new duct B, which is used for desulfurization of the flue gas by the CZD system.

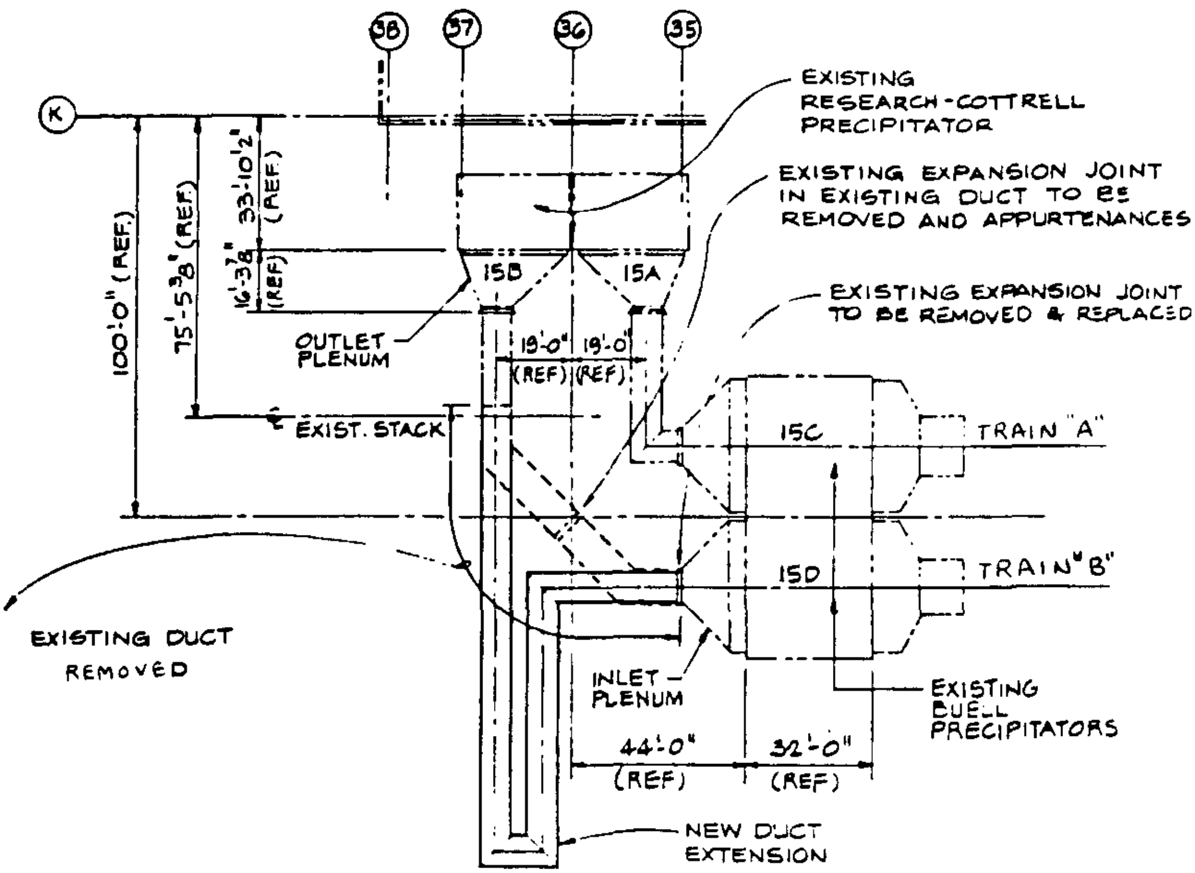


**Figure 3 Plan View of Boiler No. 15 Flue Gas Ducting**

Figure 4 presents a plan view of the desulfurization duct, which has a 110-foot-long straight run for injection of the atomized lime slurry. This is the duct length necessary for this boiler unit for the absorption of $SO_2$ from flue gas and for drying out the absorption products. The atomizing nozzles are located at the duct inlet. The duct is equipped with four sets of thermocouples at each of four duct cross section locations: B, C, D, and E. During normal operations, the B section thermocouples are not used.

Figure 5 illustrates the arrangement of thermocouples at one typical duct cross section. Single thermocouple probes can be inserted along the duct walls either 6 inches or 2 feet away from the duct walls. The near-wall thermocouples are used mainly for test purposes.

Operating instrumentation includes a low-pressure switch which will stop lime or water from being injected if the air pressure is too low to ensure adequate atomization. This instrumentation is essential for the protection of the flue gas system from the formation of wet deposits, plugging, and flooding.

A ready/standby switching system allows the lime slurry feed to the atomizers to be diverted back to the feed tanks, while water is supplied to flush the atomizing nozzles and lime supply header. The ready/standby system can be used to temporarily suspend lime injection without shutting the CZD system down and can be activated from the plant control room.

**Lime Slurry Injection**

The lime slurry injection system consists of: (1) the lime slurry and water piping, (2) the flow controls on the top of the desulfurization duct (other than the lime slurry distribution header and atomizer feeders), and (3) the water booster pump and associated water piping at ground level.

Lime slurry is supplied to the injection lime header from the lime feed system via the loop main, which consists of the feed supply and the excess feed return headers. The operation of atomizers requires relatively high, constant, lime slurry injection pressure. This pressure is maintained at a constant level at the inlet to the injection header by the back pressure controller in the lime slurry return header. The flow of the lime slurry to the atomizers' distribution header is controlled by a flow controller which is reset by the Section C temperature controller.

The lime slurry injection header is connected to the lime slurry feed loop via a four-way valve. This valve connects the lime injection header to the water supply piping from the water booster pump. The use of the four-way valve permits the lime injection header to be flushed with water whenever the lime injection is interrupted. The water supply header is furnished with a water flow controller which can be reset by the Section C temperature controller. Both the lime and water flow controller valves are connected to the low-pressure switch on the atomizing air supply header so that the operating flow control valve(s) will close in the case of low atomizing air pressure. The

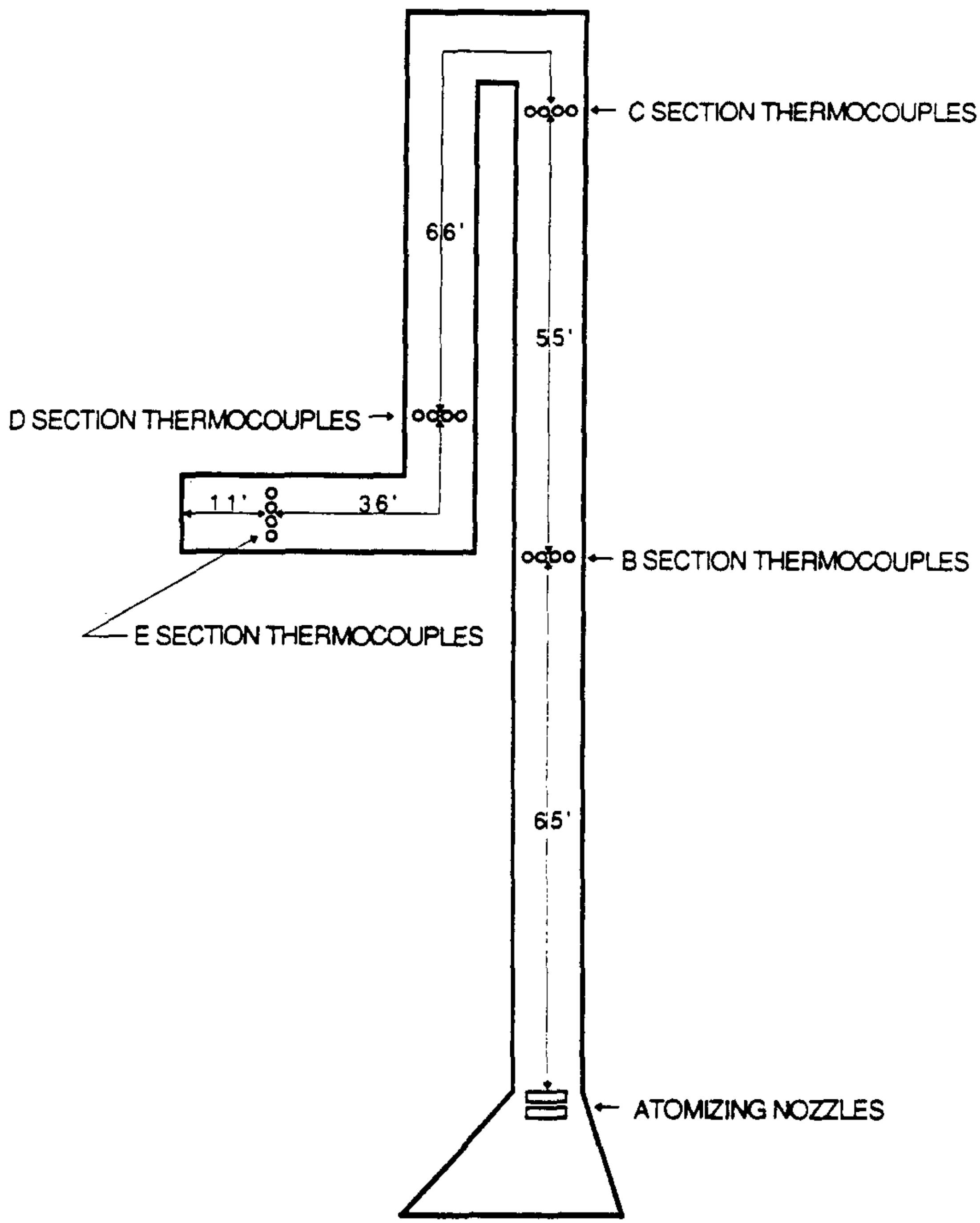


**Figure 4 Plan View of Duct with Thermocouple Locations**

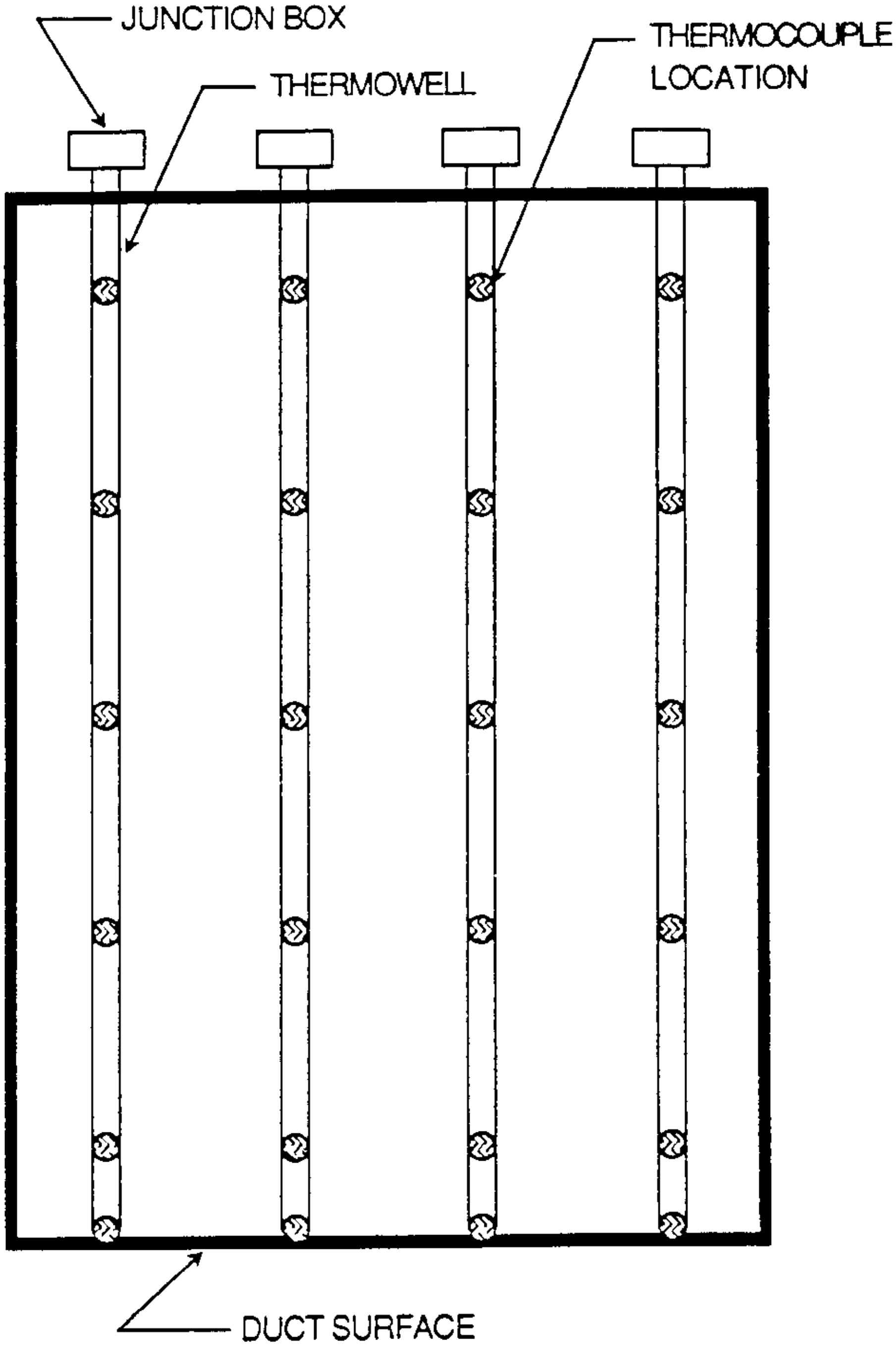


**Figure 5 Typical Thermocouple Section (6 Thermocouple per Thermowell = 24 per Section)**

arrangement protects the flue gas handling system from being flooded with unatomized lime slurry or water.

The power plant domestic water distribution system provides water for flushing the atomizers and their lime slurry supply piping and for injection into the flue gas stream. Because this system operates with a varying pressure that is inadequate for the operation of atomizers, the CZD injection system is equipped with a water booster pump to maintain an adequate water supply pressure.

**Lime Slurry Feed**

The lime slurry feed system consists of:

- One vibrating screen for the removal of foreign materials from the lime slurry,
- two grits slurry tanks, one working and one spare, both equipped with agitators and level indicators,
- two lime slurry feed tanks, one working and one spare, both equipped with agitators, level controllers, and temperature indicators, and
- two lime slurry feed pumps, one working and one spare.

The system is designed for intermittent as well as continuous plant operation; hence it has double tankage.

The vibrating screen is designed to degrit the lime slurry and is used for the removal of foreign matter from this slurry (sand, trash, etc.). Foreign materials drop from the vibrating screen into the collecting gutter from which they are sluiced with water into the grits tank.

The filtered lime slurry is discharged from the vibrating screen into the lime slurry feed tank. The slurry level in the tank is controlled by the tank level controller, which throttles the flow of lime slurry from the lime slurry sump pump to the vibrating screen.

The lime slurry feed pump is used to pump the lime from the feed tank to the lime slurry injection header. There are two pumps, one operating and one spare.

**Lime Slurry Preparation**

The lime slurry preparation system contains:

- A lime silo of 50-ton capacity, for receiving and storing lime hydrate, with a vent baghouse filter,
- a lime hydrate slurrying sump of 5,000-gallon capacity with an agitator,
- a rotary air lock valve driven by a variable-speed motor and a screw conveyor for transferring the lime hydrate from the lime silo to the sump, and

- two sump pumps, one working and one spare, for transferring the lime slurry to the CZD feed system.

**Receiving and Storing Lime Hydrate**

The existing lime silo has enough capacity for 1 day of lime usage. Consequently, daily deliveries of lime are necessary. This silo was recently upgraded for use in the CZD system. Its vent baghouse filter was fitted with new bags and its high- and low-level probes were provided with high- and low-level alarms. The rotary air discharge valve for this silo was equipped with a variable-speed motor for controlling the discharge on the hydrate to the lime slurrying sump. The speed of this rotary valve is controlled by the slurry sump density controller.

**Slurrying of Lime Hydrate in the Lime Sump**

The lime slurrying system was designed for a fully automatic operation governed by the level controller in the lime feed tank.

One of the two sump pumps is designed to operate continuously, pumping the lime slurry to the CZD lime feed system. The slurry level in the tank governs the demand for transfer of the lime slurry from the sump to the lime feed tank. The tank level controller tends to maintain a constant level in this tank by the operation of a lime flow control valve in the lime transfer line from the sump to the vibrating screen. As the transfer of the lime slurry varies, the lime slurry level in the lime sump also varies.

The lime sump is equipped with a level controller designed to maintain a constant level of slurry in the sump by controlling the sump's water inflow.

The lime sump pump bypass is equipped with a lime slurry density controller which maintains a constant concentration of lime slurry in the sump by controlling the discharge rate of lime hydrate from the silo (speed of rotation of the air lock discharge valve).

**Atomizing Air Compression System**

This system contains two screw-type air compressors (which can be operated singly or in parallel) and an air receiver. Each of the two compressors can supply up to 2,250 scfm of air at 120 psig and is driven by a 500 bhp motor. Each compressor is equipped with air intercoolers and after-coolers using 100 gpm of cooling water. The compressors are of the oilless type and provide oil-free compressed air. The operation of the CZD system requires continuous operation of at least one of the two compressors.

### Instrumentation and Control (I&C) System

Instrumentation and control (I&C) is broken down according to the plant locations at which CZD equipment and systems are found. These five operational areas/systems are:

- Lime slurry preparation system,
- lime slurry feed system,
- lime injection system,
- duct flue gas monitoring and controls, and
- atomizing air compression system.

Startup, operation, and monitoring of the equipment and systems within these areas are accomplished by a combination of actions performed locally or in the control room (remote operation). In general, initial startup of all pumps, mixers, and systems must occur locally. In this way the operator can visually verify the condition of the equipment in the area and determine whether it is safe to put the equipment or system into operation. Once a system or equipment is in operation, monitoring the condition of equipment and the changing of system setpoints can occur remotely at the control room, or locally through panel mounted switches and controllers.

The ready/standby system is also part of the CZD I&C and operates through the Bailey DCS. The ready/standby switch gives the operator a means of controlling whether or not lime slurry is injected into the duct without unnecessarily upsetting CZD controls, and safeguards the operation of the Buell ESP. Low atomizing air pressure also activates the standby mode of operation.

Remote monitoring and control of the CZD process from the control room are provided by the existing combustion management control system (MCS) and is supplemented by the process control view station (PCV). Additional plant and process operating information is available from Leeds & Northrup (L&N) recorders located in the ESP control room and in the duct B shack.

## PARAMETRIC TEST RESULTS

The parametric tests included duct injecting atomized lime slurry made of dry hydrated calcitic lime, fresh slaked calcitic lime, and pressure-hydrated dolomitic lime. All three reagents removed $SO_2$ from the flue gas, requiring different concentrations in the lime slurry for the same percent $SO_2$ removal.

The most efficient and easiest to operate is the pressure-hydrated dolomitic lime. The lime slurry duct injection does not adversely impact the stack opacity. On the contrary, it substantially reduces the stack opacity during the lime injection.

Table 1 shows typical results when using pressure-hydrated dolomitic lime.

**Table 1 Typical Results**
**Parametric Demonstration Tests with Pressure-Hydrated Dolomitic Lime**

| Date | August 21, 1992 | | August 24, 1992 | |
|---|---|---|---|---|
| Item Time | 21:57 | 22:12 | 17:33 | 18:13 |
| Boiler load, MW | 136.0 | 142.8 | 143.69 | 143.57 |
| Flue gas temp. in, °F | 303.7 | 304.0 | 309.68 | 308.77 |
| Flue gas temp. out, °F | 189.1 | 190.30 | 192.70 | 191.30 |
| Stack opacity, % | 6.7 | 7.8 | 11.95 | 11.75 |
| $SO_2$ in, ppm | 965.71 | 929.77 | 877.38 | 866.91 |
| $SO_2$ out, ppm | 360.87 | 350.38 | 342.90 | 342.40 |
| $SO_2$ in, scfm | 181.95 | 178.43 | 161.83 | 160.98 |
| $SO_2$ out, scfm | 84.83 | 83.40 | 80.08 | 79.71 |
| $SO_2$ removal, % | 53.87 | 53.26 | 50.52 | 50.48 |

## TECHNOLOGY APPLICABILITY AND LIMITATIONS

### Commercial Application

CZD technology is particularly well suited for retrofitting existing boilers, regardless of type of boiler, age, size, type of coal burned, or percent of sulfur in the coal. Unlike currently available flue gas desulfurization systems, CZD technology can be more easily and economically integrated into existing power plants.

The inherent advantages of the CZD process relative to currently available commercial technologies are:

- Substantially lower capital cost and total cost per ton of $SO_2$ removed,
- easy to retrofit, because it eliminates the need for chimney alterations, boiler reinforcements, and modifications to boiler draft controls,
- no increase in flue gas pressure drop; therefore, no extra fans or booster fans needed,
- no effect on the existing stack; therefore, no modifications are required,
- minimal space requirements in the stack area,
- no dewatering or liquid waste treatment required,
- no liquid waste and no flue gas reheating requirement,
- no congestion close to the boiler or stack,
- reacted products that are dry, free-flowing, and easily disposable, and are mixed with fly ash, and

- reduced labor force and maintenance requirements.

A disadvantage is its limitation in $SO_2$ removal to about 50 percent.

Additionally, the CZD technology is not limited by:

- Geographic applicability,
- load profile applicability,
- particulate collector requirements (either ESP or baghouse),
- waste disposal factors, and
- raw material requirements (dolomitic rock is well distributed in many areas of the United States).

The CZD process requires that drying and reaction normally take place within 1, or possibly 2 seconds. The injection of finely atomized sprays and the use of a reactive reagent combine to achieve these results.

A long straight flue gas duct of 60 to 100 feet which could ensure a residence time of 1 to 2 seconds, will make the CZD technology applicable to a retrofit condition of about 50 percent $SO_2$ removal. If the flue gas duct, as described, is not available and there are space limitations for a new horizontal long duct, then a vertical duct of the required length could be built to make the CZD technology applicable.

## Commercial Demonstration

The CZD project is designed to demonstrate:

- Reliable operation of the CZD process when integrated with power stations,
- no detrimental effect on normal boiler operations, and
- its capability to operate with high- and low-sulfur coal.

If the demonstration is successful, the results should enable Bechtel to commercialize the CZD process. Reference 6 describes flue gas desulfurization by the CZD process on a comparative basis with economies of other clean coal technologies. The CZD process flow diagram for a 500 MWe unit burning 4 percent sulfur coal is shown in Figure 6.

## Utilization of Demonstrated Results

During the CZD demonstration, technical papers giving technical and economic data, results, and conclusions, will be presented at different conferences. These papers will be made available for publication in appropriate journals of technical societies, the electric generating industry, and in other publications. Representatives of utilities will be invited to visit the demonstration site and learn how $SO_2$ can be removed cost-effectively using the CZD process.

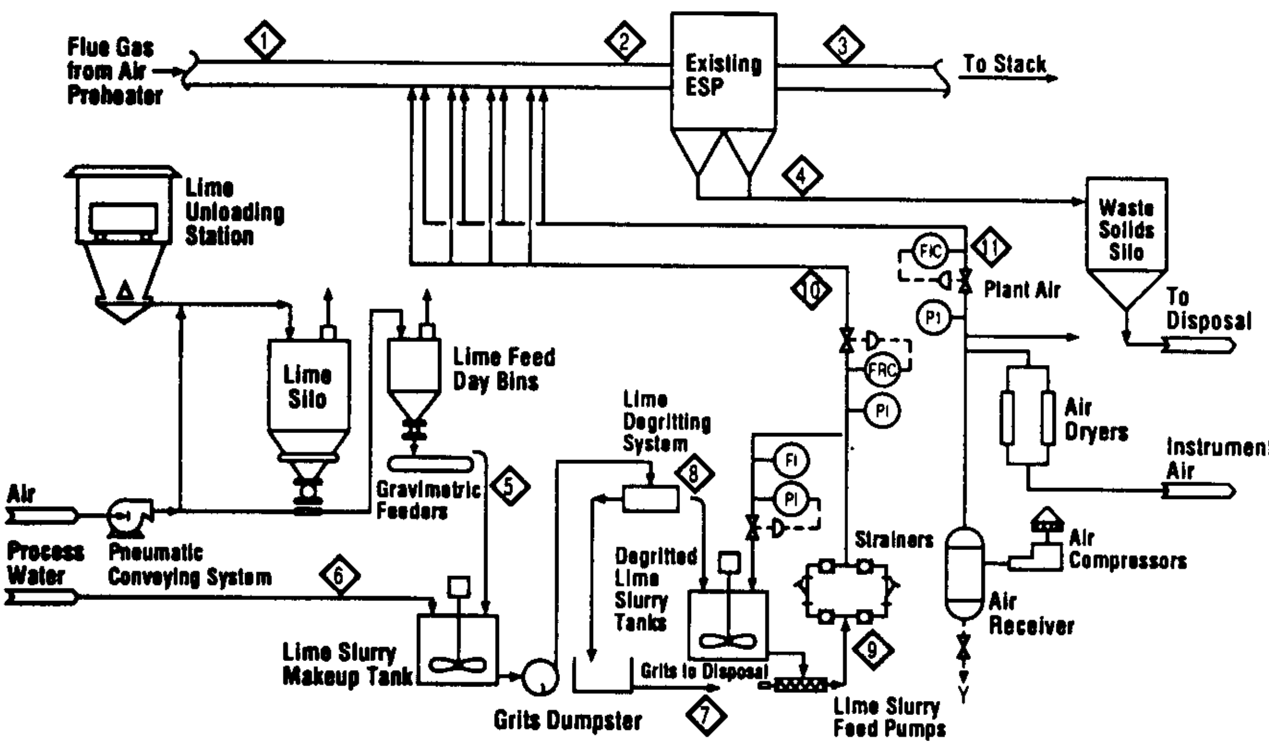


**Figure 6 CZD Process Flow Diagram – 500 MWe Unit Burning 4% S Coal**

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# LIFAC SORBENT INJECTION FOR FLUE GAS DESULFURIZATION

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## ABSTRACT

This paper discusses the demonstration of LIFAC sorbent injection technology at Richmond Power and Light's (RP&L) Whitewater Valley Unit #2 under the auspicies of the U.S. Department of Energy's (DOE) Clean Coal program. LIFAC is a sorbent injection technology capable of removing 75 to 85 percent of a powerplant's $SO_2$ emissions using limestone at a calcium to sulfur molar ratios of between 2 and 2.5 to 1. The site of the demonstration is a coal-fired electric utility powerplant located in Richmond, Indiana, which is between Indianapolis, Indiana and Dayton, Ohio. The project is being conducted by LIFAC North America, a joint venture partnership of Tampella Power Corporation and ICF Kaiser Engineers, in cooperation with DOE, RP&L,, and several other organizations including the Electric Power Research Institute (EPRI), the State of Indiana, and Black Beauty Coal Company.

## INTRODUCTION

The Clean Coal Technology program (CCT) has been recognized in the National Energy Strategy as a major initiative whereby coal will be able to reach its full potential as a source of energy for the nation and the international marketplace. Attainment of this goal depends upon the development of highly efficient, environmentally sound, competitive coal utilization technologies responsive to diverse energy markets and varied consumer needs. The CCT Program is an effort jointly funded by government and industry whereby the most promising of the advanced coal-based technologies are being moved into the marketplace through demonstration. The CCT program is being implemented through a total of five competitive solicitations, four of which have been completed. This paper discusses the LIFAC sorbent injection technology which was selected in the third round of CCT solicitations.

LIFAC North America, Inc., a joint venture of ICF Kaiser Engineers, Inc. and Tampella Ltd. of Finland, will demonstrate the LIFAC flue gas desulfurization technology developed by Tampella. This technology provides sulfur dioxide emission control for power plants, especially existing facilities with tight space limitations. Sulfur dioxide emissions are expected to be reduced by up to 85% by using limestone as a sorbent. The limestone is injected into the upper regions of a boiler furnace, where calcining to lime and partial absorption of $SO_2$ occur. Subsequently, the combustion gas is passed through a unique piece of equipment known as the activation chamber. This is a vertical elongation of the ductwork between the air preheater and ESP where the combustion gas is humidified and $SO_2$ absorption is completed. The LIFAC technology will be demonstrated at Whitewater Valley 2, a 60-MWe coal-fired powerplant owned and operated by Richmond Power and Light (RP&L) and located in Richmond, Indiana. The Whitewater plant consumes high-sulfur coals with sulfur contents ranging from 2.4 - 2.9 percent sulfur.

The project, co-funded by LIFAC-NA and DOE, is being conducted with the participation of Richmond Power and Light, the State of Indiana, the Electric Power Research Institute, and the Black Beauty Coal Comapny. The project has a total cost of 22 million dollars and a duration of 48 months from the preliminary design phase through the testing program.

The sponsors of this project believe that LIFAC has the potential to be a new and important $SO_2$ control option for U.S. utilities subject to the Clean Air Act's acid rain regulations. To be considered as a commercially feasable option in this particular emissions control market, LIFAC must demonstrate a high $SO_2$ removal rate while remaining competitive with other options on a cost per ton of $SO_2$ removed basis. To this end, the sponsors of this project have designed the demonstration with the following goals in mind:

- Sustained High $SO_2$ Removal Rate - Incorporated into the test plan are several periods of long term testing which are intended to demonstrate LIFAC's $SO_2$ removal and reliability characteristics under normal operating conditions.

- Cost - LIFAC must compete with both low capital cost, low $SO_2$ removal rate options such as sorbent injection and high capital cost, high $SO_2$ removal rate options such as wet scrubbing. This project will demonstrate LIFAC's competetiveness on a cost per ton of $SO_2$ removed basis with these currently available alternatives.

- Retrofit Adaptability - The host site chosen required a retrofit with tight construction conditions that will prove LIFAC's ability to be installed where other technologies might not be possible. Construction will also demonstrate LIFAC's ability to be built and brought on-line with zero plant down time other than scheduled outages.

- System Compatibility - A major concern of utilities is the degree of compatibility of $SO_2$ removal systems with their existing operations. This demonstration will show LIFAC's minimal impact on the host site's boiler and associated subsystems.

## LIFAC PROCESS HISTORY AND DESCRIPTION

In 1983, Finland enacted acid rain legislation which applied limits on $SO_2$ emissions sufficient to require that flue gas desulfurization systems have the capability to remove about 80 percent of the sulfur dioxide in the flue gas. This level could be met by conventional wet limestone scrubbers but not by then available sorbent injection technology. Tampella Corporation, therfore, began developing an alternative sorbent injection system which resulted in the LIFAC process.

Initially, development first involved laboratory and pilot plant tests, then full-scale tests of sorbent injection of limestone. Using high-ash, low-sulfur coal and a Ca/S molar ratio of three to one, Tampella was unable to achieve a 50 percent $SO_2$ removal rate at it's 160 megawatt Inkeroinen facility. Substitution of lime for limestone was rejected due to its high cost.

Subsequent research and development by Tampella led to the addition of a humidification section after the furnace which became known as the LIFAC process. The sorbent injection process was installed full scale on a 220 megawatt boiler located at Kristiinankaupunki, Finland and a side-stream representing 2.5 megawatts was used to test a small scale humidification reactor. $SO_2$ removal rates of up to 84 percent were achieved at this plant. Additional tests at the Neste Kulloo combustion laboratory were conducted at 8 megawatts and also achieved 84 percent removal rates.

In 1986, the first large full scale test was performed at Imatran Voima's Inkoo powerplant using a 70 megawatt side-stream from a 250 megawatt boiler. A 76 percent $SO_2$ removal rate with 1.5% sulfur coal was reached. A second LIFAC activation chamber was constructed to handle an additional 125 megawatt side-stream. This newer reactor is achieving removal rates of 75 to 80 percent while using Ca/S molar ratios of between 2 and 2.5 to 1. Also in 1988 the first tests with high-sulfur U.S. coals were run at the Neste Kulloo Laboratory. A Pittsburgh #8 Seam coal containing 3 percent sulfur was tested and an $SO_2$ removal rate of 77 percent was achieved with Ca/S molar ratios of 2 to 1.

## LIFAC Process Description

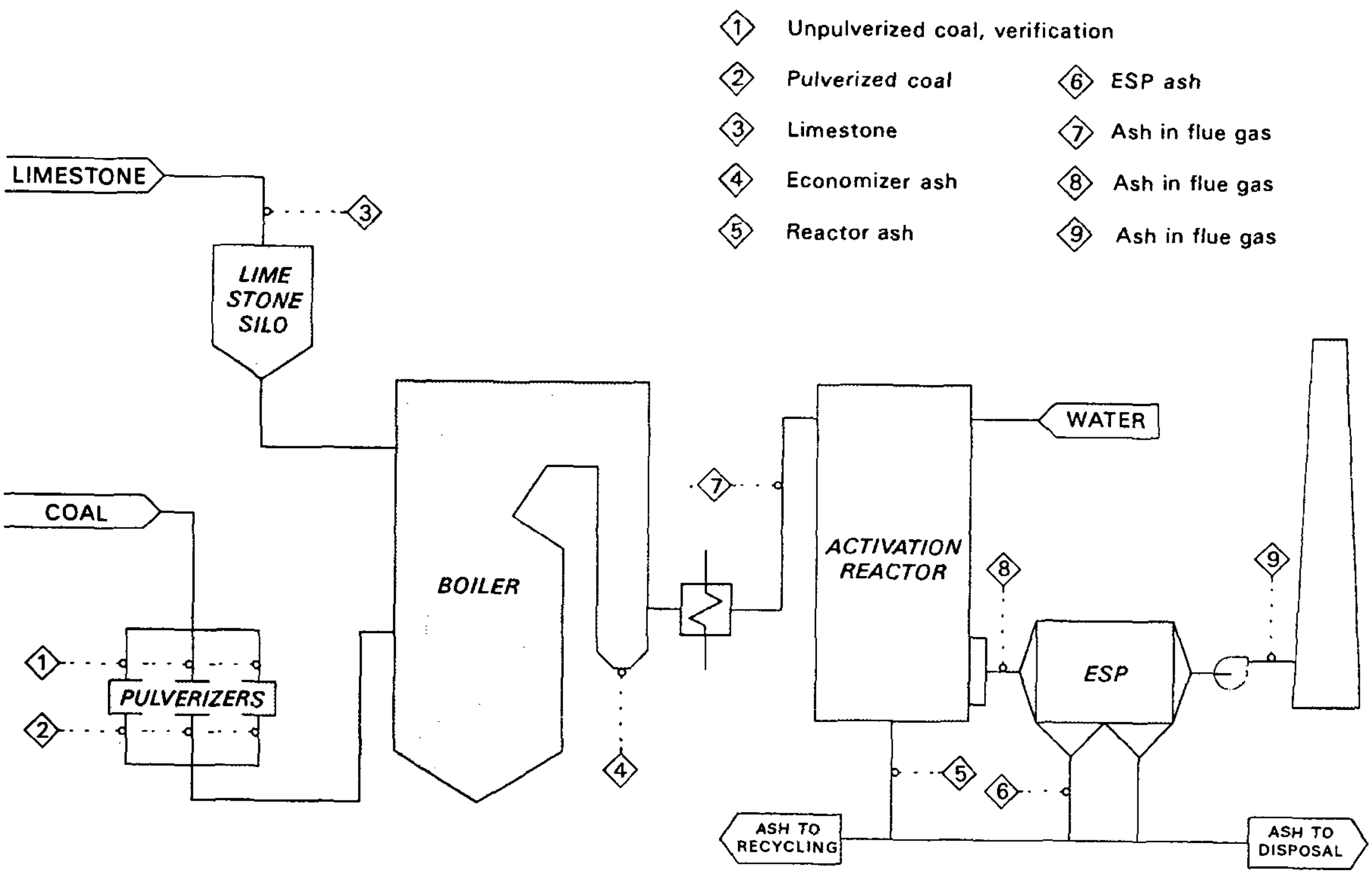
The LIFAC system combines conventional limestone injection into the upper furnace region with a post-furnace humidification reactor located between the air preheater and the ESP. The process produces a dry, stable waste product that is removed from both the bottom of the humidification reactor and the ESP.

Finely pulverized limestone is pneumatically conveyed and injected into the upper region of the boiler where temperatures are approximately 1800 to 2200 degrees Farenheit. At these temperatures the limestone ($CaCO_3$) calcines to form lime ($CaO$) which readily reacts with the $SO_2$ to form calcium sulfate ($CaSO_4$). All of the sulfur trioxide ($SO_3$) reacts with the $CaO$ to form $CaSO_4$.

Approximately 25 percent of the sulfur dioxide removal occurs in the boiler with the remaining 75 percent and the unreacted lime passing through the air preheater to the humidification reator. There the flue gas is sprayed with water that allows the unreacted lime to hydrate to $Ca(OH)_2$ which more readily reacts with the sulfur dioxide and forms $CaSO_3$. A combination of the proper water droplet size and residence time allows for effective hydration of the lime and complete water evaporation to create a dry reactor bottoms product.

After exiting the humidification reactor, the flue gas is reheated before entering the ESP. The humidification and lower gas temperature enhance the efficiency of the ESP. Seventy-five percent of the LIFAC-produced spent sorbent and fly ash is collected by the ESP with the other 25 percent collected by the humidification reactor. Both the reactor and ESP ash may be recycled to a point before the reactor to improve the $SO_2$ removal efficiency of the system to the range of 75 to 85 percent. A schematic of the LIFAC process is shown in Figure 1 along with the typical sampling locations used during the demonstration.

## LIFAC RP&L Demonstration



Process Advantages

LIFAC is similar to other current sorbent injection technologies but has unique advantages with its use of a patented vertical humidification reactor. And while LIFAC's sulfur dioxide removal efficiency is not as high as traditional wet flue gas desulfurization systems, its cost and simplicity of design, construction and operation offer other advantages over these alternative systems. In particular the advantages of the LIFAC system are as follows:

- High $SO_2$ removal rates - Currently available sorbent injection systems have been unable to sustain high $SO_2$ removal rates with any consistency. LIFAC has proven in the past and intends to demonstrate during this project the ability to achieve and sustain high $SO_2$ removal rates of 70 to 80 percent over long operating periods.

- By-products - Wet lime and limestone scrubbing systems create a wet by-product ash that must be further treated before disposal. LIFAC produces a dry solid waste ash containing calcium sulfide, calcium sulfate and fly ash. This waste is easily disposed of under U.S. regulatory requirements, may be recycled to increase LIFAC's efficiency and may have commercial applications in the cement industry.

- Compatiblity and Adaptability - LIFAC has minimal impact on the host's site and systems, primarily the boiler, ESP and ID fan. In addition, LIFAC requires little space and few utilities and therefore is easily installed even in small or cramped powerplant sites.

## CONSTRUCTION AND SYSTEMS INTEGRATION

Construction of the LIFAC system has occurred in two phases over a period of one and a half years. The first phase of construction was completed during a routine plant outage in March, 1991. The period was utilized to install tie-ins to the host site's existing systems.

Ductwork and three dampers were installed between the air preheater and ESP to allow flue gas flow to the LIFAC activation reactor. Tie-ins were also made to the powerplant's high pressure steam, condensate and river water supplies. The steam and condensate will be required to reheat the flue gas exiting the LIFAC reactor and the water is needed for flue gas humidification inside the reactor. Injection ports were also installed in the boiler walls above the nose elevation.

The second phase of construction began in the Fall of 1991 with the driving of reactor piling and the installation of underground conduit runs. Work continued through to the Summer of 1992 with no need for plant downtime other than normally scheduled outages. During this time the limestone storage area was completed and the injection system was installed on Unit #2. The activation reactor was constructed and then tested with both cold air during a scheduled Unit #2 outage and hot flue gas during a low electricity demand period. Other powerplant tie-ins such as the steam and condensate system were also tested during low demand periods in the evening or at night.

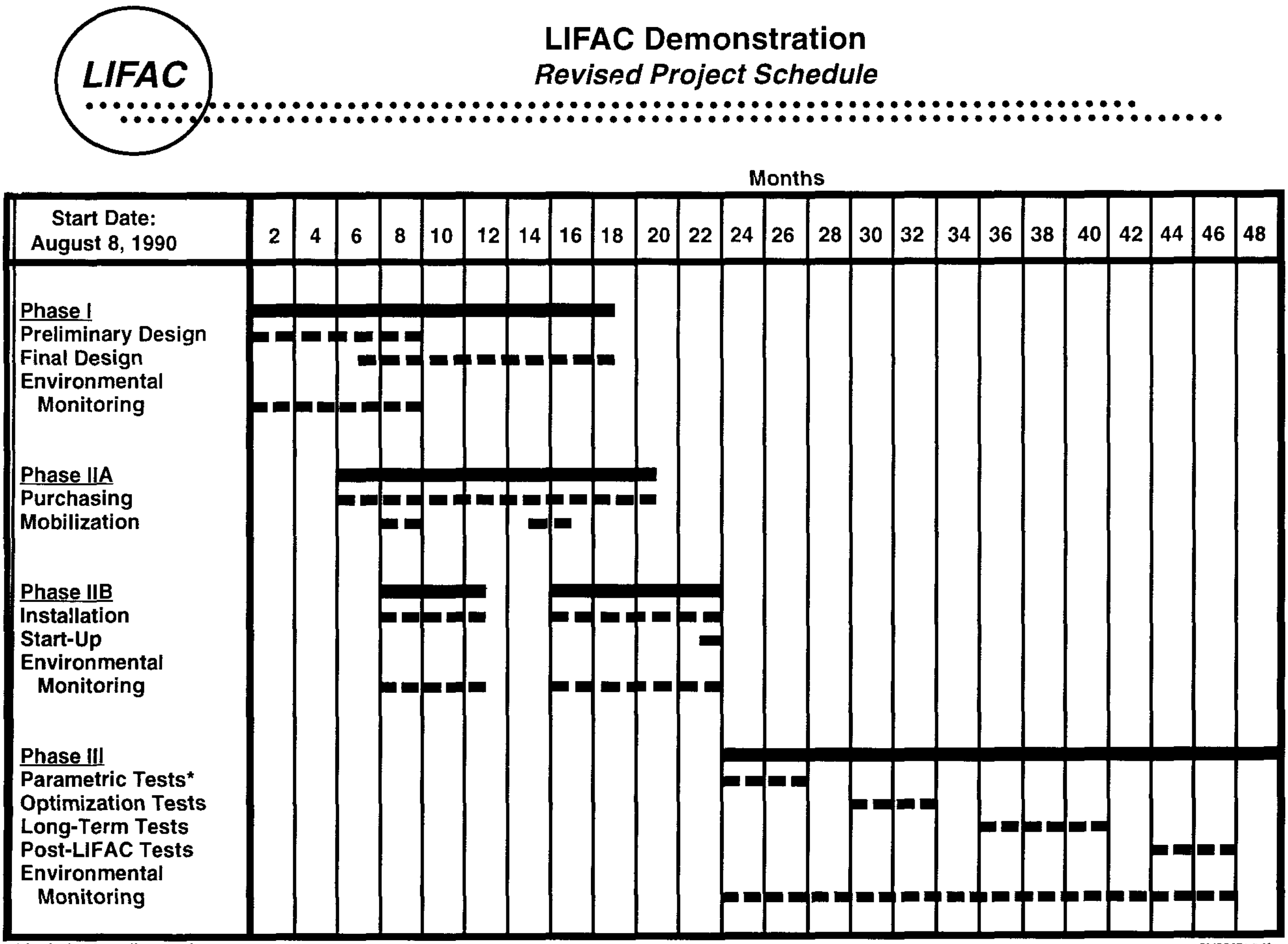
All of the construction work associated with the LIFAC system was performed in close proximity to the exterior of the powerplant or in cramped areas inside the plant. The ductwork tie-ins and new steelwork required inside the plant are located in small, difficult to access work areas. The reactor outside is approximately thirty feet from the powerplant with the outside ductwork and piping crossing offices and other plant roof areas. All of these new structures and equipment were constructed with no interference to daily plant operations.

## SCHEDULE

The current schedule for the LIFAC demonstration program extends over a three and one half year period from the DOE Cooperative Agreement signing date of November 1990 through the testing program to be completed in the Summer of 1994 (see Figure 2). The LIFAC system was originally scheduled to come on-line in June of 1992 but due to delays in receiving construction permits this date has been moved to September of 1992. Although

# LIFAC Demonstration

*Revised Project Schedule*




* Includes baseline testing.

PM7/LIFAC-92

testing is scheduled to continue through the end of the project in the Summer of 1994, preliminary test results will be available towards the end of 1992. The following are significant milestones that have either occurred or are upcoming under the revised construction schedule:

- November 1990 - Cooperative Agreement signed between LIFAC-NA and DOE for LIFAC proposal chosen under Round III of DOE's Clean Coal Technology Program.

- March 1991 - Construction of tie-ins to powerplant systems completed during a scheduled outage.

- November 1991 - Construction began after a three month delay in receiving construction permits from the State of Indiana. Ground was broken with the commencement of pile driving for the reactor.

- June 1992 - During a scheduled outage, ambient air is successfully passed through the recently completed reactor vessel.

- July 1992 - During a low boiler loading period, hot flue gas is successfully passed through the reactor vessel using the LIFAC damper control system.

- September 1992 - LIFAC scheduled to come on-line. Baseline testing of the boiler and its subsystems will have been completed by this point.

- November 1992 - Preliminary test data will be available on LIFAC's emission controls performance and its effects on the host site's systems.

- Summer 1994 - Scheduled completion of all testing. Complete reports will be issued evaluating LIFAC's emission controls performance, its effect on the host site and its economic feasability.

Currently the demonstration project is on track with this revised construction schedule. All work, excluding some reactor area lighting and leveling and grading, was completed at the begining of August. Equipment check-out was performed in August with limestone deliveries scheduled for the end of the month. Pending the arrival of the sorbent material, limestone injection into the boiler along with post-furnace humidification will begin in September 1992.

## TEST PLAN

The test plan for the LIFAC demonstration is composed of five distinct phases, each with its own objective. The five phases need to be performed in a certain order as test conditions and settings in one phase will be dependent on the results obtained in prior phases. The first of these phases will consist of the initial baseline testing portion of the project. Measurements will be taken that will characterize the operation of the host's boiler and associated subsystems prior to the use of the LIFAC system. The results will be used for comparison purposes with the LIFAC system in operation and with data collected at the end of the project to determine any changes in the host's systems.

The second, or parametric, phase of testing will be performed next to determine the best combination of LIFAC process variables for $SO_2$ removal. The variables to be studied in this phase include the limestone injection nozzles' angle and location, the Ca/S molar ratio, the need for supplemental injection air at the boiler, the water droplet size and injection nozzle arrangement in the reactor, the ash recycling ratio and the approach to saturation temperature of the flue gas exiting the reactor vessel. The best combination of these variables will be chosen at the conclusion of this phase and used for the remainder of the test program.

Optimization tests will follow parametric testing and will examine the effects of different coal and limestone feeds on the $SO_2$ capture rate. Coals with sulfur contents as high as 3.3 percent will be tested to determine LIFAC's compatibility with high sulfur U.S. coals.

Limestones with different compositions will also be tested to determine the LIFAC system's adaptability to local sorbent sources.

The long term testing phase will be performed after the optimization tests to demonstrate LIFAC's performance under commercial conditions. The LIFAC system will be in operation 24 hours per day for several weeks using the powerplant's baseline coal, high calcium limestone and the optimum combination of process variables. In addition to process performance measurements, during this phase the operation and maintainence requirements of the system will be examined.

The final phase of testing is composed of the post-LIFAC tests. The baseline phase testing will be repeated to gather information on the condition of the boiler and its associated subsystems. Comparisons will be made to the baseline data to identify any changes either caused by the LIFAC system or independant of its operation.

Schedule

The current schedule for LIFAC testing spans 26 months from June 1992 to July 1994. The baseline and post-LIFAC testing phases each last approximately one month at the begining and end of the test program respectively. The parametric and optimization tests will each consist of two to three months of LIFAC system testing with an additional two month period for data compilation, handling and reporting. The long term testing phase will occur over a seven month time frame composed of three to four week continuous testing periods followed by several weeks of reporting.

Results

Test results for Richmond Power and Light's Unit #2 are not currently available but data have been collected from a similar LIFAC system installed at Saskatchewan Power Corporation's Poplar River Power Station located in Canada. In September of 1990 tests were begun at the plant with sorbent injection to a 300 MWe furnace and humidification of

150 MWe of flue gas. A complete set of parametric, optimization and long term tests were performed over the next eleven months.

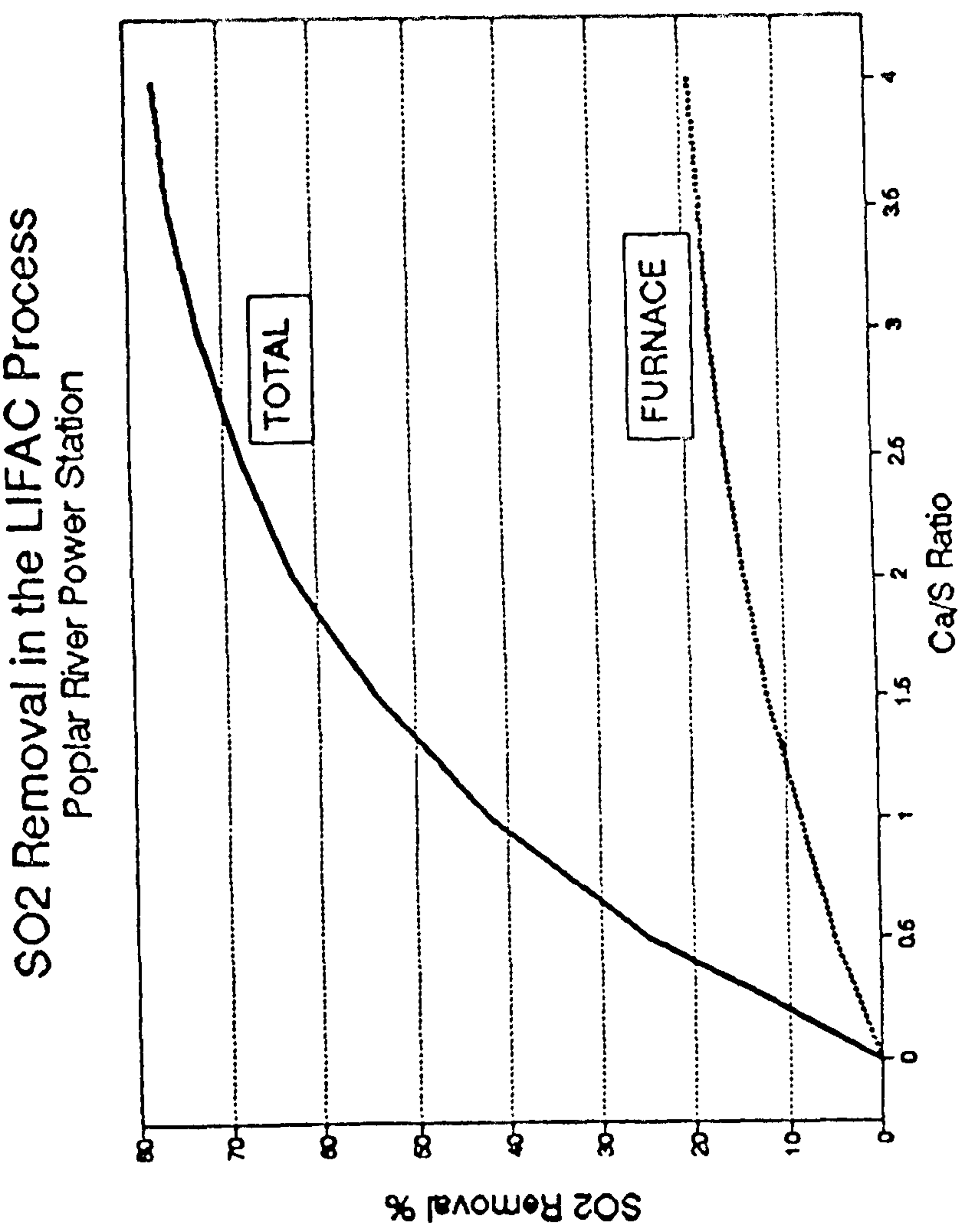
As was predicted by process modelling prior to the operation of the LIFAC system, sulfur dioxide capture in the furnace at Poplar River was limited due to the high temperatures at the furnace injection location and the short furnace residence time of the limestone. A 16 percent $SO_2$ capture rate was acheived in the furnace and was almost entirely depedent on the Ca/S molar ratio (see Figure 3). Supplemental air, predicted by the modelling to increase furnace capture to 24 percent, was added at the boiler injection nozzles but had no measurable effect along with the other furnace process variables.

The humidification section contributed by far the largest portion of the $SO_2$ capture, with its performance improving as the reactor outlet temperature dropped. The reactor was successfully operated at approach temperatures down to 7 degrees F. Ash recycling accouinted for approximately one quarter of the reactor ash removal.

The total resulting $SO_2$ removal (furnace & humidification) rate with a Ca/S molar ratio of 2.2 to 1 was 66 percent at a 300 MWe boiler load. By reducing the load to 200 MWe, overall removal was improved to 70 percent with the same Ca/S ratio. Changing furnace parameters other than the Ca/S ratio had no measurable effect on the $SO_2$ removal rate in the reator.

Manpower requirements were also studied during this project and Tampella Power estimated that about 3000 extra man hours per year would be needed to operate and maintain a LIFAC unit with a sorbent injection capacity of 300 MWe and humidification of 150 MWe.

In conclusion, the demonstration project at the Poplar River Power Station showed that the LIFAC system can be installed and operating without effecting normal powerplant operations. It also proved that the system can economically reduce $SO_2$ emissions when compared with other flue gas desulfurization technologies.


SO2 Removal in the LIFAC Process
Poplar River Power Station
TOTAL
FURNACE
SO2 Removal %
0
10
20
30
40
50
60
70
80
Ca/S Ratio
0
0.5
1
1.5
2
2.5
3
3.5
4

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# THE CLEAN COAL TECHNOLOGY PROGRAM: 10 MWe DEMONSTRATION OF GAS SUSPENSION ABSORPTION FOR FLUE GAS DESULFURIZATION


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U.S. DEPARTMENT OF ENERGY
FIRST ANNUAL
CLEAN COAL TECHNOLOGY CONFERENCE
September 22-24, 1992
Cleveland, Ohio


## ABSTRACT


This paper presents a description of the Gas Suspension Absorption technology and a status report on the Clean Coal Technology project entitled "10 MW Demonstration of Gas Suspension Absorption" that AirPol is currently performing with the cooperation of the Tennessee Valley Authority under a Cooperative Agreement with the United States Department of Energy. This low-cost retrofit project seeks to demonstrate the Gas Suspension Absorption system which is expected to remove more than 90% of the sulfur dioxide ($SO_2$) from coal-fired flue gas, while achieving a high utilization of reagent lime.

**INTRODUCTION**

AirPol, with the assist
Gas Suspension Abs
entitled "10 MW Dem
demonstration under
of Energy (DOE) in

- Compare removal efficiency and cost with existing Spray Dryer/Electrostatic Precipitator technology.

DOE is in the process of reviewing a proposal for an additional scope of work which includes air toxics testing and operation and testing of a 1 MWe fabric filter. The two-fold purpose of this additional work will be to:

- Determine the air toxics removal performance of the GSA system.
- Compare the $SO_2$ and air toxics removal performance between a GSA system with an electrostatic precipitator and a GSA system with a fabric filter.

The fabric filter can be connected either upstream or downstream of the electrostatic precipitator. Testing of the fabric filter will be conducted for both configurations.

The total budget for the project with the added scope of work is $7,720,000; however, the project cost is currently under budget. The favorable variance has resulted mainly from actual material and construction costs being much lower than the original estimate. The performance period of the project, including the air toxics and fabric filter testing, is from November 1990 to February 1994.

AirPol began design work on this two-year project in November 1990 shortly after award of the Cooperative Agreement in October 1990. At the outset of the project, site access was delayed by TVA to allow the U.S. Environmental Protection Agency to complete pilot tests on a R&D project. This caused a one-year delay to this Clean Coal Technology project. The design phase of the project was completed in December 1991. Fabrication and construction of the GSA unit was completed ahead of schedule during the construction phase which runs through September 1992. The one-year operation and testing of the demonstration unit will begin in October 1992, and a dedication ceremony is planned for October 27, 1992.

## HISTORY OF THE GSA TECHNOLOGY

GSA is a novel concept for flue gas desulfurization developed by AirPol's parent company, F.L. Smidth miljo a/s in Copenhagen, Denmark. The gas suspension absorber was initially developed as a cyclone preheater system for cement kiln raw meal (limestone and clay). This innovative system provided both capital and energy savings by reducing the rotary kiln length requirement and lowering fuel consumption. The gas suspension reactor showed superior heat and mass transfer characteristics and was subsequently used for the calcination of limestone, alumina, and dolomite. The GSA system was later developed by injecting lime slurry and recycled solids to the bottom of the gas suspension reactor, which functions as an acid gas absorber.

In 1985, a GSA pilot plant was built in Denmark to establish design parameters for $SO_2$ and hydrogen chloride (HCl) absorption for incineration applications. The first commercial GSA unit was installed at the KARA Waste to Energy Plant at Roskilde, Denmark in 1988. Currently, there are six (6) GSA installations in Europe, and all are for municipal solid waste applications.

With the increased emphasis on $SO_2$ emissions reduction by electric utility and industrial plants as required by the Clean Air Act Amendments of 1990, there is a definite need for a simple and economic process, such as GSA, by the small to mid-size plants where a wet flue gas desulfurization system is not economically feasible. The GSA process, with commercial and technical advantages to be confirmed by this demonstration project, is expected to meet the needs of the U.S. utility and industrial markets.

## GSA PROCESS DESCRIPTION

The GSA system, as shown in Figure 1, consists of:

- A circulating fluidized reactor.
- A separating cyclone incorporating a system for recycling separated material to the reactor.
- A slurry preparation system which proportions the slurry to the reactor via a nozzle.
- A dust collector which removes flyash and reacted lime from the gas stream.

The flue gas from the boiler is fed into the bottom of the reactor where it is mixed with the suspended solids wetted with lime slurry. The solids consist of reaction products, residual lime and flyash.

During the drying process in the reactor, the lime slurry undergoes a chemical reaction with the acid components, $SO_2$ and HCl of the flue gas, capturing and neutralizing them.

The partially cleaned flue gas flows through the separating cyclone to an electrostatic precipitator, or a fabric filter, which removes the dust and ash particles. The flue gas, which has now been cleaned, is then released into the atmosphere through the stack.

The solids are separated from the gas stream in the cyclone. Approximately 95% to 99% of the solids is fed back to the reactor via a screw conveyor, while the remaining solids leave the system as a waste product. The 95% to 99% which is recirculated to the reactor is still reactive. This means that the recirculated lime is still able to react with and neutralize the acid gas in the flue gas. In addition, the flyash in the flue gas makes a positive contribution in the neutralization process to a much higher degree than in conventional semi-dry flue gas cleaning plants.

The GSA process provides an extremely efficient utilization of the lime slurry and flyash, thus minimizing the need for the introduction of fresh lime.

One of the reasons for the high efficiency of the GSA process is that the absorber is based on gas suspension technology. This means that a very high concentration of flyash, dust particles, and lime is fluidized inside the reactor. This concentration will normally be as high as 200-800 grains/SCF.

Automatic Process Adjustment

An effective monitoring and control system automatically ensures the required level of cleaning while keeping lime consumption to a minimum. This GSA control system, as shown in Figure 2, incorporates three control loops:

1. The first loop continuously controls the flow of recycled solids to the reactor, based on the amount of flue gas entering the system. The large reaction area and even distribution in the reactor of the absorbent provides for efficient mixing of the lime with the flue gas. At the same time, the large volume of dry material prevents the slurry from adhering to the sides of the reactor.

2. The second control loop ensures that the flue gas is sufficiently cooled to optimize the chemical processes. This is achieved by the addition of extra water along with the lime slurry. The amount of water added into the system is governed by the temperature of the flue gas exiting the reactor to avoid any risk of acid condensation.

3. The third control loop controls lime addition. This is accomplished by continuously monitoring the acid content in the outlet flue gas and comparing it with the required emission level. This control loop enables direct proportioning of lime feed according to monitored results and further contributes to maintaining a low level of lime consumption.

## GSA ADVANTAGES OVER COMPETING TECHNOLOGY

Simplicity is the GSA system's key feature and major advantage over competing technologies such as spray drying.

### Slurry Atomization

The main advantage of the GSA process over other competing technologies is in the means the reagent is introduced and used for $SO_2$ absorption. A spray dryer

- requires a costly and sensitive high speed rotary atomizer for fine atomization,
- absorbs $SO_2$ in an "umbrella" of finely atomized slurry with a droplet size of about 50 microns, and
- requires multiple nozzle heads to ensure fine atomization and full coverage of the reactor cross section.

Whereas the GSA

- uses a low pressure dual fluid nozzle,
- absorbs $SO_2$ on the wetted surface of suspended solids with superior mass and heat transfer characteristics, and
- uses only one spray nozzle for the purpose of introducing slurry and water to the reactor.

As a result, the GSA process is more economical and efficient than the spray dryer.

### Low Lime Consumption and Minimum Waste Product Residue

Efficient utilization of the lime absorbent as a result of the lime recirculation and precision process control not only lowers the lime consumption, but also reduces the amount of waste product from the system.

### Low Maintenance Operation

Unlike other types of semi-dry scrubbers, the GSA has no moving parts in the reactor, thus ensuring continuous trouble free and maintenance free operation. The inside diameter of the GSA injection nozzle is much greater than that of a conventional spray dryer, and there is little chance for it to plug up. Nozzle wear is also minimized. Should the need of replacing the nozzle arise, the nozzle can be replaced in a few minutes without interrupting operations. The inside surface of the reactor is continuously "brushed" by the suspended solids and is kept free of any build-up, which is a common problem with the conventional spray dryer.

Flexibility

Operation of the GSA process will not result in additional dust loading in the flue gas, so this process can be installed both in new and existing plants by either adding a new dust collector or utilizing the existing dust collector. The GSA system operation is not limited to a specific type of dust collector, so either a fabric filter or an electrostatic precipitator can be used.

Modest Space Requirements

Due to the high concentration of solids suspended in the reactor, which allows adequate reaction to take place in a relatively short period of time, a higher velocity (16 to 22 feet per second as compared to 4 to 6 feet per second for a spray dryer) and shorter residence time (2 to 3 seconds as compared to 7 to 11 seconds for a spray dryer) is achieved in the GSA design. This allows for a shorter and smaller reactor which leads to a considerable reduction in material and space requirements.

Short Construction Period

The compact design of the GSA unit requires less manpower and time to be erected as compared to the typical semi-dry scrubbers. Despite its relatively complicated tie-ins and extremely tight work space, the retrofit GSA demonstration unit at the TVA Shawnee Test Facility was erected in three and a half months. The erection of a new GSA unit would take less than three months.

Lower Costs

The capital investment for a GSA system is generally 20% lower than that of the typical semi-dry scrubber. Lower operating and maintenance costs are achieved as a result of reduced lime consumption and maintenance requirements.

## PROJECT STATUS AND KEY MILESTONES

The project schedule and tasks involved in the design, construction, and operation and testing phases are as follows:

| | | Start - End |
|---|---|---|
| **Phase I - Engineering and Design** | | |
| 1.1 | Project and Contract Management | 11/01/90-12/31/91 |
| 1.2 | Process Design | 11/01/90-12/31/91 |
| 1.3 | Environmental Analysis | 11/01/90-12/31/91 |
| 1.4 | Engineering Design | 11/01/90-12/31/91 |
| **Phase II - Procurement and Construction** | | |
| 2.1 | Project and Contract Management | 01/01/92-09/30/92 |
| 2.2 | Procurement and Furnish Material | 01/01/92-04/30/92 |
| 2.3 | Construction and Commissioning | 05/01/92-09/30/92 |
| **Phase III - Operating and Testing** | | |
| 3.1 | Project Management | 10/01/92-02/28/94 |
| 3.2 | Start-up and Training | 10/01/92-10/14/92 |
| 3.3 | Testing and Reporting | 10/15/92-02/28/94 |

Phase I was completed on time according to the revised project schedule incorporating the one-year delay in obtaining the host site. Phase II is essentially complete, except for project management activities and commissioning. By the end of September 1992, the GSA unit and associated equipment will be tested and ready for operation. In October 1992, flue gas will be diverted to the GSA system, and the operation and testing of the system and the fabric filter will be carried out by the TVA Shawnee Test Facility personnel.

## TEST PLAN

A test plan has been prepared to depict in detail the procedures, locations, and analytical methods to be used in the tests. The following objectives are expected to be achieved by testing the GSA system:

- Optimization of the operating variables.
- Establishment of stoichiometric ratios for various $SO_2$ removal efficiency requirements.
- Evaluation of erosion and corrosion information at various locations in the system.
- Demonstration of 90% or greater $SO_2$ removal efficiency.
- Determination of the GSA system's air toxics removal performance.
- Evaluation of the performance of fabric filter when used in conjunction with GSA.
- Verification of AirPol's process calculation basis.

### Optimization Tests

$SO_2$ removal optimization tests will be performed by adjusting one controllable variable at a time. Upon completion of these tests, different combinations of the optimum setting of the controllable variables will be tested to arrive at the optimum operating point for the GSA system.

Variables which are not expected to fluctuate are:

- Inlet gas volume
- Inlet $SO_2$ loading
- Inlet HCl loading
- Inlet humidity

Controllable variables that will be varied in different test series for process optimization purposes are:

- Inlet gas temperature
- Reinjection of waste into the reactor
- Lime slurry concentration and feed rate
- Reactor outlet saturation temperature and approach to saturation temperature
- Cooling water rate
- Calcium chloride addition

Data Collection

The following data will be sampled and recorded during the tests by either the computerized data sampling and recording system via field mounted instruments or manual field testing:

- Gas flow at inlet of the system
- $SO_2$ and HCl loading at the system inlet, $SO_2$ loading at the electrostatic precipitator inlet and the electrostatic precipitator outlet
- $O_2$ at the system inlet, the electrostatic precipitator inlet, and the electrostatic precipitator outlet
- Temperature at the system inlet, the reactor outlet, and the electrostatic precipitator outlet
- Particulate loading at the GSA system inlet, the electrostatic precipitator inlet, and the electrostatic precipitator outlet
- Slurry flow (for stoichiometric lime to acid ratio calculation)
- Slurry concentration
- Water flow
- Dew point temperature at the electrostatic precipitator outlet (for approach to saturation temperature calculation)
- Coal analysis
- Flue gas analysis (concurrent with coal analysis)
- Lime analysis
- Waste product rate

- Waste product analysis
- Water analysis
- Power consumption
- Corrosion rate in the reactor, cyclone, and electrostatic precipitator

Data Analysis

Monthly reports will be provided by TVA describing the tests performed and discussing the test results. Data collected from the tests will be analyzed to determine the optimum setting of the key operating variables.

Demonstration Run

Based on the findings during the optimization period, the GSA system will be operated at optimum settings for a four-week consecutive period to demonstrate the reliability of the system operation as well as its $SO_2$ removal capability. During the demonstration run, all controls will be switched to automatic mode with set points determined from the optimizing tests.

## COMMERCIALIZATION

One of the objectives of the demonstration project is for AirPol to establish its capability in designing, manufacturing, and constructing the GSA system so that the demonstrated technology can be effectively commercialized for the benefit of the U.S. electric utility and industrial markets. During the course of designing the demonstration unit, an effort was made by AirPol to standardize the process design, equipment sizing, and detail design so that the design of a commercial unit can be accomplished within a relatively short time frame. There was also an effort made during the design phase to achieve simplicity in the equipment design, which later proved to contribute to reduced material cost. In order to obtain first-hand experience in constructing a GSA system, AirPol used its own construction team to erect the system. This will enable AirPol to offer a turnkey system in a competitive market.

## DISCUSSION

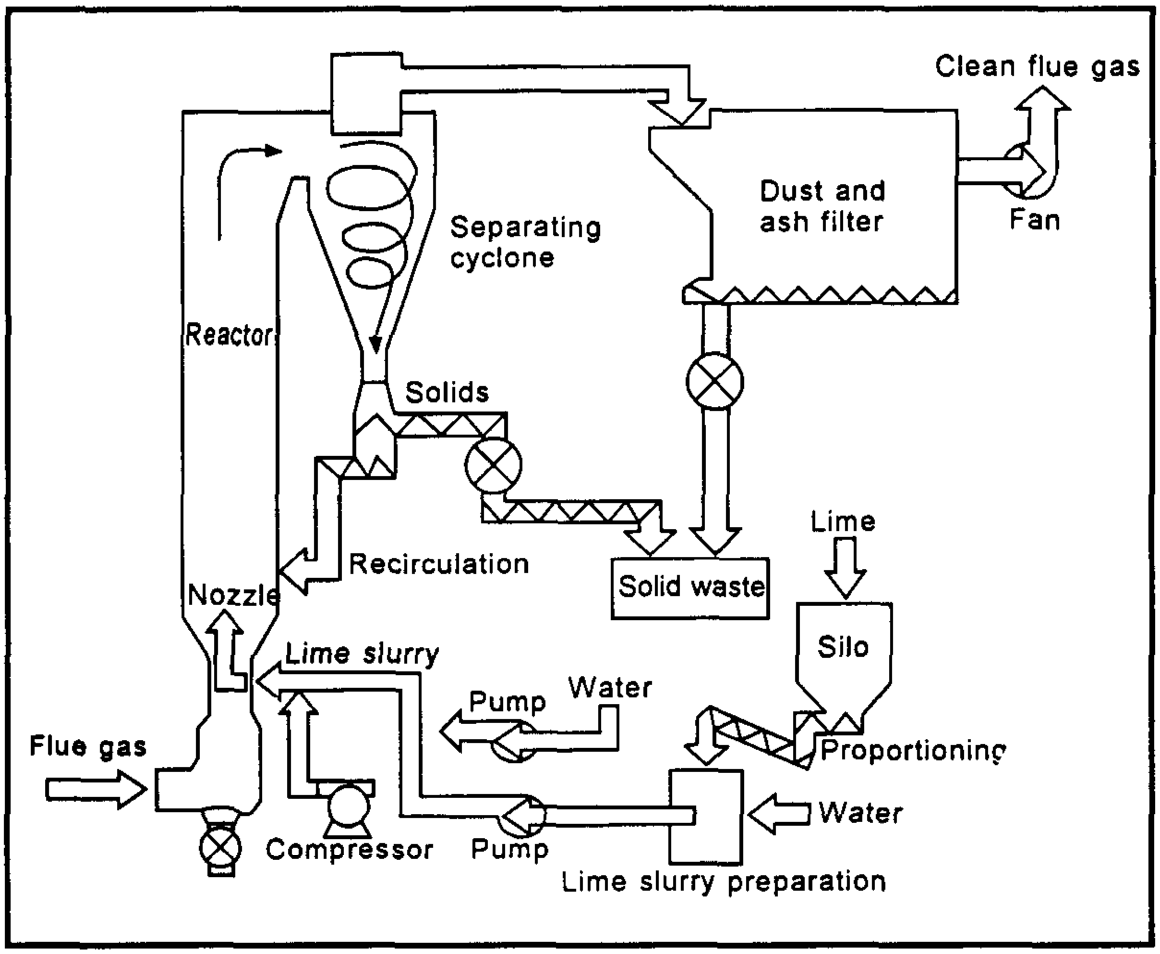
As of September 1992, the design, fabrication, and construction of the GSA system for the Clean Coal Technology demonstration project will have been completed. Preparation for the next phase, operation and testing of the GSA system, is underway and all activities are expected to be on schedule. Although the performance of the GSA system is yet to be demonstrated, AirPol has demonstrated the ease and economy of retrofitting this system into an existing plant, especially with respect to time, and material and construction costs.

Recent test results from a waste incineration plant in Denmark indicate that GSA is not only effective in removing acid from the flue gas but also capable of removing heavy metals such as mercury, cadmium, and lead. With the addition of air toxics testing and fabric filter testing to the Clean Coal Technology test program, the results of this demonstration project will further confirm the GSA system's advantages in coal-fired boiler applications.

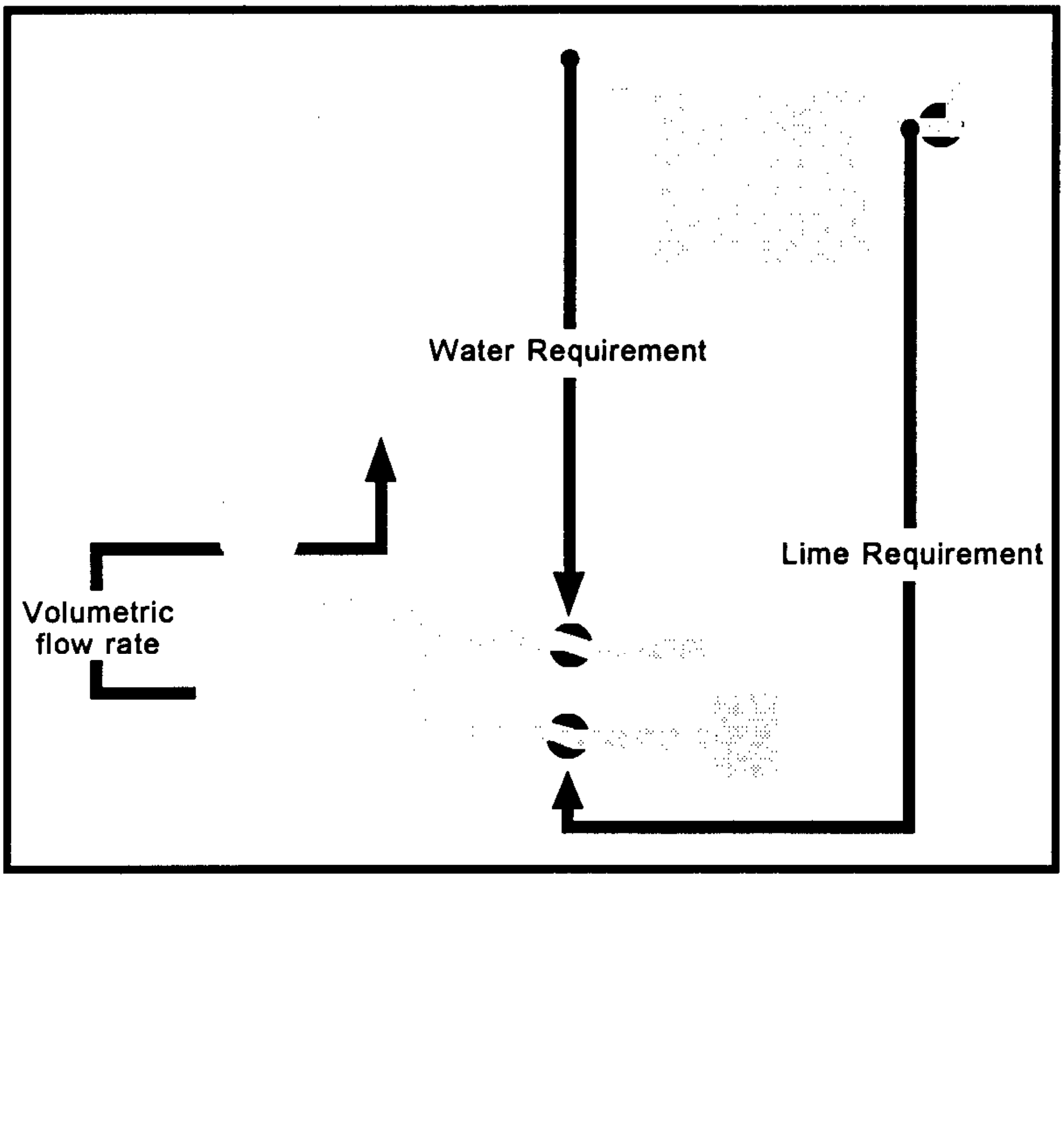
## DISCLAIMER

Reference in this report to any specific commercial product, process, or service is to facilitate understanding and does not necessarily imply its endorsement or favoring by DOE.

**Figure 1. Gas Suspension Absorption Process Flow Diagram**



## Figure 2. Gas Suspension Absorption Control System



# FINAL RESULTS OF THE DOE LIMB AND COOLSIDE DEMONSTRATION PROJECTS

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## INTRODUCTION

Within the past decade increasing emphasis has been placed on the control of pollutant emissions from a variety of sources in the United States. Prominent among these are sulfur dioxide ($SO_2$) and nitrogen oxides ($NO_x$), gases that result from the combustion of fossil fuels and are commonly considered to be among the major sources of acid rain. The automotive and power industries are therefore intimately involved in the process of technology development to reduce potential emissions. The largest man-made, stationary sources of both gases are coal-fired utility boilers which account for about 65% of the $SO_2$ and 29% of the $NO_x$ emissions in the United States.[1]

The Clean Air Act Amendments (CAAA) of 1990 now constitute the primary regulatory directive that describes control requirements for $SO_2$ and $NO_x$ emissions from utilities. This legislation provides for phased compliance and gives utilities the ability to choose the technology needed to meet emission limits. Since they were passed in November 1990, the utility industry has chosen fuel switching and wet flue gas desulfurization systems (FGD scrubbers) as the primary means of meeting the CAAA's Phase I requirements on larger units. These requirements place a 2.5 $lb/10^6$ Btu cap on $SO_2$ emissions, with a target date of January 1, 1995. After that, other technologies are expected to be regarded as viable, given a wide variety of site-specific considerations. Limestone Injection Multistage Burner (LIMB) is one such technology. The process involves the injection of a calcium-based sorbent into the furnace for $SO_2$ capture. This is coupled with the use of low-$NO_x$ burners, to reduce emissions of $NO_x$. Another similar technology is the Coolside flue gas desulfurization (FGD) process. This $SO_2$ removal process involves the injection of a dry sorbent downstream of the air heater followed by flue gas humidification.

In 1987, Babcock & Wilcox (B&W), the Ohio Edison Company, and the Consolidation Coal Company (now CONSOL, Inc.) agreed to extend the full-scale demonstration of LIMB technology under the sponsorship of the U.S. Department of Energy (DOE), through its Clean Coal Technology Program, and the state of Ohio Coal Development Office (OCDO). The original LIMB demonstration had begun in 1984 under the sponsorship of the U.S. Environmental Protection Agency (EPA) and OCDO.[2] The DOE project also provided for demonstration of the Coolside FGD process between July 1989 and February 1990. The DOE LIMB Extension test program was conducted between April 1990 and August 1991. All demonstration tests, LIMB and Coolside, were carried out on the 105 MWe, coal-fired Unit 4 boiler at Ohio Edison's Edgewater Station in Lorain, Ohio.

This paper highlights the results of the Coolside Process Demonstration, presents a summary of the results of the LIMB Extension program, and addresses the economics of $SO_2$ removal with LIMB and Coolside in comparison to those with Limestone Forced Oxidation (LSFO) FGD technology.

## OBJECTIVES

The primary purpose of the LIMB Extension was to demonstrate the generic applicability of LIMB technology. The program sought to characterize the $SO_2$ emissions that result when various calcium-based sorbents are injected into the furnace, while burning coals with a range of sulfur content from 1.6 to 3.8%. The effects of certain process variables on $SO_2$ removal efficiency were demonstrated. These included inlet calcium/sulfur stoichiometry (Ca/S) for each sorbent used, inlet $SO_2$ concentration resulting from coals of different sulfur content, the degree of humidification, injection at various elevations (temperatures), and particle size distribution for the limestone sorbent. The impact of sorbent injection on particulate emissions is also examined in terms of the opacity, while $NO_x$ emissions are characterized as a result of continued use of the low-$NO_x$ DRB-XCL™ burners. The ease of operation and the reliability of the LIMB system are described in light of the various process parameters tested; the overall economics of LIMB, Coolside, and wet LSFO FGD technology are compared.

The major objectives of the Coolside Demonstration were to characterize the $SO_2$ emissions that result when injecting two different calcium-based sorbents while burning high sulfur coal. The short term operability at a commercial scale was demonstrated and a data base to design a commercial Coolside installation was developed. The final objective of this portion of the project was to develop process economics.

## GENERAL PROCESS DESCRIPTIONS

A flow diagram of the LIMB process is shown in Figure 1. A brief description of the Edgewater equipment is provided here; a more detailed description of the Edgewater LIMB design was presented in an earlier paper.[3]

The process begins with the injection of a calcium-based sorbent into the furnace at the upper end of a 2300 to 1600F sulfation temperature window where it calcines to active calcium oxide, and then reacts with sulfur dioxide and oxygen in the flue gas to produce

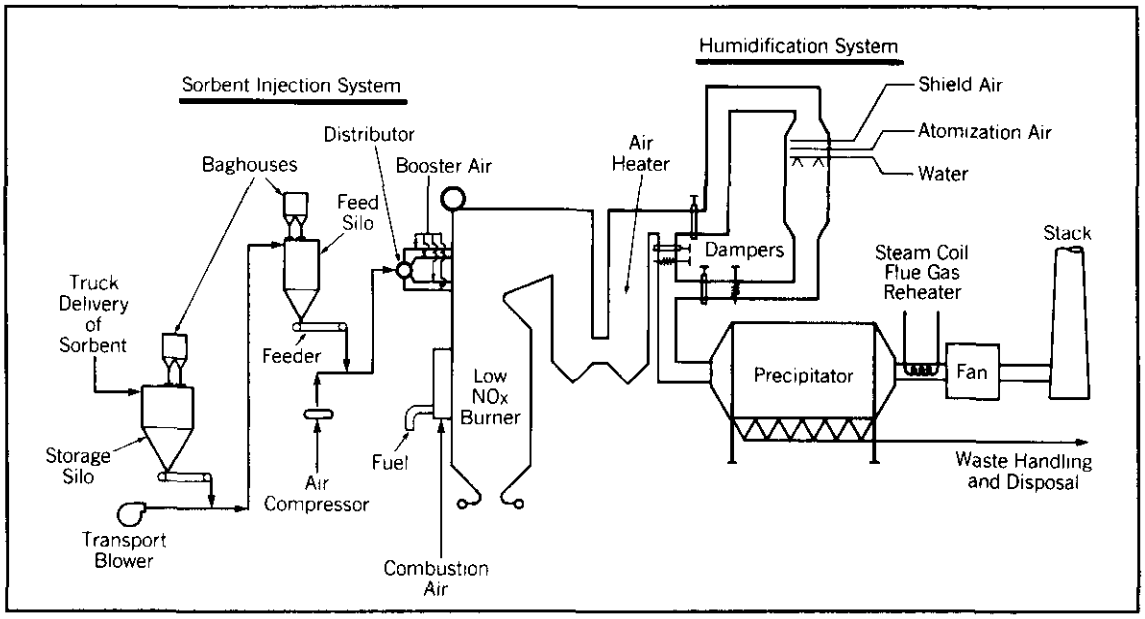


**Figure 1. LIMB process flow diagram.**

calcium sulfate. The solid reactant products and fly ash (LIMB ash) exit the boiler with the flue gas. Prior to entering the electrostatic precipitator (ESP), the flue gas is humidified using water sprays to decrease the resistivity of the LIMB ash. After collection in the ESP, the LIMB ash is stored in a silo. It is then wetted in a pug mill-type ash unloader, discharged into trucks, and disposed of in a landfill.

Low-$NO_x$ burners achieve reduced levels of emissions by virtue of their keeping flame temperatures relatively low.

The Coolside process at Edgewater utilized the same equipment as the LIMB process with the following differences:

- The hydrated lime is injected into the boiler outlet duct at the location of the humidification water sprays rather than into the furnace. The flue gas temperature at this location is about 300F.
- The boiler exit flue gas is humidified down to a 20F approach to adiabatic saturation (approximately 145F) rather than just low enough to maintain ESP performance (approximately 275F). Here, humidification activates the sorbent to enhance $SO_2$ removal and conditions the ash for removal by the ESP.

- A sodium additive (sodium hydroxide was used at Edgewater) is added to the humidification water to enhance the sorbent activity.

- An ash recycle system is utilized to inject recycled ash from the ash storage silo into the boiler outlet duct at the same location as lime injection. Sorbent utilization is improved by ash recycle.

- A steam reheater is utilized to reheat the cooled flue gas before it enters the existing stack.

A detailed description of the Coolside process is presented in an earlier publication.[4] The following summarizes the results and conclusions of the Coolside demonstration program.

## HIGHLIGHTS OF THE COOLSIDE DEMONSTRATION

### $SO_2$ Removal

Using a commercially available hydrated lime, the Coolside process achieved 70% $SO_2$ removal while operating at the following design conditions:

| | |
|---|---|
| Coal sulfur content | 2.8 to 3.0% |
| Calcium-to-sulfur molar ratio | 2.0 |
| Sodium-to-calcium molar ratio | 0.20 |
| Approach to adiabatic saturation temperature | 20F |

It was found that the Coolside process is most sensitive to the calcium-to-sulfur molar ratio, the sodium-to-calcium molar ratio, and the approach to the adiabatic saturation temperature. Coal sulfur content did not significantly affect $SO_2$ removal.

### Sorbent Utilization and Recycle

At Coolside design operating conditions sorbent utilization was about 33%. It was confirmed that significant $SO_2$ removal capacity remains in the spent sorbent. This was confirmed by an observed $SO_2$ reduction of 22% when only recycle ash was injected. It was also shown that sorbent selection plays an important role in the performance of the Coolside process. Of the two commercially available hydrated limes tested at Edgewater, one provided 5 to 10% (absolute) higher $SO_2$ removal at equivalent conditions.

Operability and Reliability

The Coolside demonstration at Edgewater was intended for short-term test operation and was not designed to establish long-term process operability, though a continuous test run of 11 days did indicate its feasibility. The operational problems identified during the demonstration were horizontal humidifier floor deposits, atomizer nozzle wear, and deposits on the atomizer nozzles. These problems could be easily addressed in a commercial design. In particular, it was concluded that a vertical design for the humidification chamber would resolve the operating problems associated with the horizontal humidification chamber at Edgewater. A hopper installed at the bottom of a vertical humidification chamber would permit collection and removal of any ash and deposit accumulations. Ceramic inserts, installed for the LIMB Extension that followed Coolside, easily overcame atomizer nozzle wear problems, as was expected from their use in slurry service in dry scrubber applications.

Particulate Collection

Particulate collection was not a problem during the Coolside demonstration at Edgewater, with stack opacity normally less than 10%. A degradation in ESP performance was realized at high ESP inlet solids loading and subsequent ESP internal inspection revealed the formation of deposits on the high tension wires farthest from the rappers. Several changes were made to the ESP rapper and energization control sequences which produced some improvement. It was determined that particular attention to ESP design parameters would need to be made for a commercial Coolside system.

Coolside Waste

Coolside waste contains fly ash, unreacted hydrated lime ($Ca(OH)_2$), calcium sulfite ($CaSO_3$), calcium sulfate ($CaSO_4$), and small amounts of sodium sulfite ($Na_2SO_3$), sodium sulfate ($Na_2SO_4$), and calcium carbonate ($CaCO_3$). It was found to be non-hazardous according to the EP (Extraction Procedure) Toxicity Test outlined in the Resource Conservation and Recovery Act (RCRA), and was disposed of in a permitted landfill. The high lime content of Coolside ash causes it to have cementitious properties that can make it easier to dispose than typical coal fly ash.

## THE LIMB EXTENSION PROGRAM RESULTS

### Test Conditions

The LIMB Extension test program was designed to determine the $SO_2$ removal efficiency for four sorbents: calcitic limestone ($CaCO_3$), "type-N" atmospherically hydrated dolomitic lime [$Ca(OH)_2 \cdot MgO$], and calcitic hydrated lime [$Ca(OH)_2$], both alone and with added calcium lignosulfonate (hereafter referred to as ligno lime). These tests were conducted over a range of Ca/S molar ratios and humidification conditions, while burning Ohio coals with nominal sulfur contents of 1.6, 3.0, and 3.8% by weight. The coal/sorbent combinations of 3.0% sulfur coal with calcitic hydrated lime and ligno lime, tested during the EPA-sponsored program, were not repeated during the LIMB Extension. However, the 3.0% sulfur coal/ligno lime combination was used to verify equivalent system operation following conversion of equipment back to a furnace injection configuration after the Coolside duct injection tests were complete. The ability to maintain compliance with the plant's emission limits was demonstrated during continuous operation of the LIMB system with the lime sorbents while burning the higher sulfur coals.

Tests were also performed with two more finely ground calcitic limestones. This occurred because the more coarse material originally used resulted in an unexpectedly low $SO_2$ removal efficiency (discussed in more detail later in this section). Plans for tests with the 3.8% sulfur coal and limestone were canceled when even the finest limestone failed to show removal efficiencies that would maintain compliance with the plant's 30-day rolling average emission limit of 3.4 lb $SO_2/10^6$ Btu during tests over a range of stoichiometries.

The same analytical methodology used during the EPA-sponsored program, including both manual sampling and the use of a continuous emission monitoring system (CEMS), was continued throughout the DOE project. The CEMS provided continuous measurements of $SO_2$, $NO_x$, $O_2$, CO, and $CO_2$ concentrations in the flue gas just before the stack. The analyses of truck and bunker samples were monitored on a daily basis to assure use of the desired coal during any test period. Calcitic lime samples were analyzed on-site for available lime [as $Ca(OH)_2$]. Commercial Testing and Engineering Company (CTECo) analyzed limestone for total calcium, and dolomitic lime for both calcium and magnesium by atomic absorption spectrophotometry.

An on-site Leco sulfur analyzer was used during tests as a more immediate measure of coal sulfur. This was done to verify the stability of the "inlet" $SO_2$ condition. Ultimate analyses of composited pulverized coal samples were performed by CTECo on a five work day/week basis. Again, this was the same procedure used during the original EPA LIMB Demonstration.

The matrix of tests associated with the coal/sorbent combinations is presented in Table 1, which also summarizes the number of tests used to generate the results of the LIMB Extension project. Formal test periods with steady-state conditions ranged from 30 to 710 min in duration, with an average length of 134 min. Those conditions run during the EPA project are included to show the overall scope of LIMB testing.

## Overall $SO_2$ Reductions

The primary independent variables in the study were sorbent type and sulfur content of the coal burned. The different sorbents were tested, when possible, while burning each of the three different coals. Other test variables were Ca/S stoichiometry, humidifier outlet temperature, and injection elevation in the boiler. The previous EPA LIMB testing had demonstrated that $SO_2$ removal efficiencies of 55 to 60% were obtainable while injecting commercial calcitic hydrated lime at an inlet Ca/S molar ratio of 2.0 with minimal

**Table 1. Number of tests used to characterize $SO_2$ removal efficiency.**

| Sorbent | Nominal coal sulfur, wt % 1.6 | 3.0 | 3.8 |
|---|---|---|---|
| Calcitic hydrated lime | 14 | EPA* | 8 |
| Ligno lime | 34 | 8† | 23 |
| Dolomitic hydrated lime | 29 | 33 | 24 |
| Limestone 80% < 44$\mu$m | 12 | 20 | NT‡ |
| Limestone 100% < 44$\mu$m | 15 | NP** | NP |
| Limestone 100% < 10$\mu$m | 4 | NP | NP |

* Tests were run during the EPA-sponsored demonstration
† Tests were run to confirm system performance after the switch back to furnace injection from duct injection
‡ NT = Not tested due to projected difficulty in maintaining compliance with the plant's emission limit of 3.4 lb/$10^6$ Btu
** NP = Not planned

humidification. This testing also showed that removal efficiencies of approximately 65% were possible while injecting ligno lime at similar conditions.

LIMB Extension testing showed that, when operating at a Ca/S ratio of 2.0 and injecting at the 181 ft level, $SO_2$ removal efficiencies across the range of coal sulfur contents tested were 53 to 61% for ligno lime, 51 to 58% for commercial calcitic lime, 45 to 52% for dolomitic lime, and 22 to 25% for limestone ground to 80% less than 44$\mu$m (325 mesh). The results of testing ligno, dolomitic, and calcitic limes, and limestone at the 181 ft injection level while burning 1.6% sulfur coal and varying Ca/S ratio are presented in Figure 2. The results of testing at the numerous other test conditions are presented in the LIMB Demonstration Project Extension and Coolside Demonstration Final Report.[5]

Effect of Sorbent Type

During the LIMB Extension, ligno lime and calcitic hydrated lime exhibited the highest removal efficiencies of the sorbents tested at any given stoichiometry. $SO_2$ reductions on

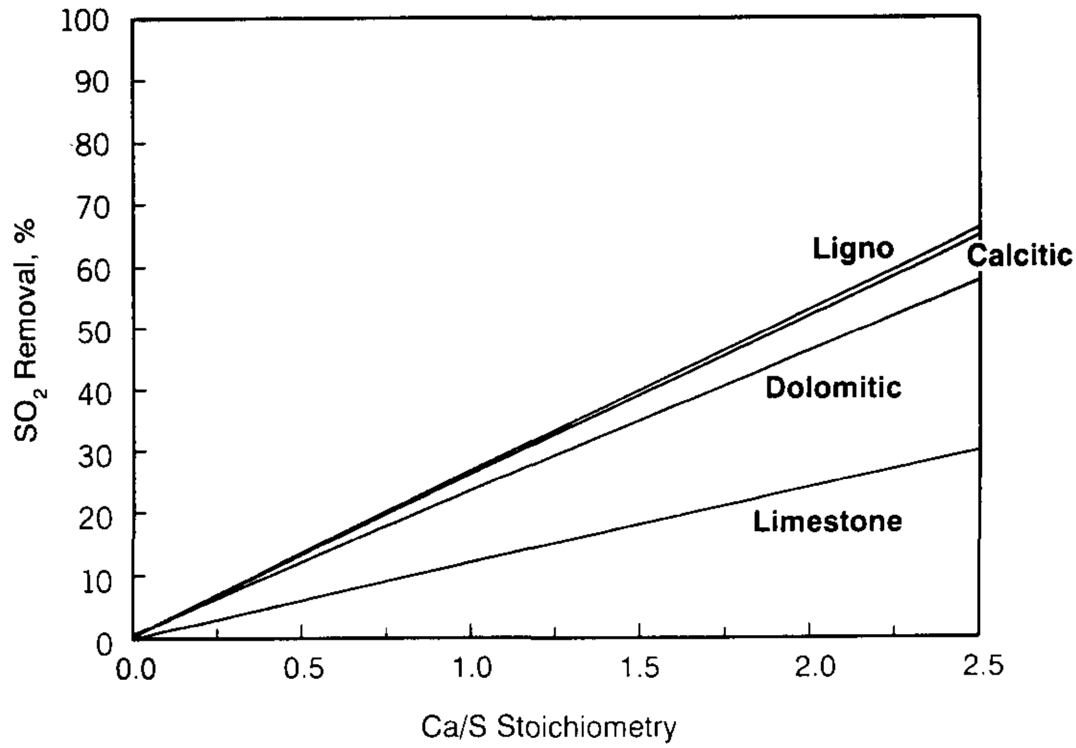


**Figure 2. Effect of different sorbents on $SO_2$ removal while burning 1.6% sulfur coal and injecting at elevation 181 ft.**

the order of 60% were obtained at a Ca/S ratio of 2.0 with minimal humidification. Dolomitic hydrated lime effected about 50% removal at the same conditions. Removals ranged from about 20 to 40% for calcitic limestone depending on the choice of grind (particle size distribution).

Table 2 presents the $SO_2$ removal efficiencies for the four sorbents tested at the 181 ft boiler elevation at a Ca/S ratio of 2.0 across the range of coal sulfur content tested.

## Effect of Coal Sulfur Content

The sulfur content of the coal, as reflected in the $SO_2$ concentration of the flue gas, appeared to have a small, but perceptible, effect on the $SO_2$ removal efficiency. It was found that the higher the sulfur content, the greater the $SO_2$ removal for a given sorbent at

**Table 2. $SO_2$ removal efficiencies for injection at 181 ft level at a 2.0 Ca/S ratio with minimal humidification.**

| Sorbent | Nominal coal sulfur content, wt % | | |
|---|---|---|---|
| | 3.8 | 3.0 | 1.6 |
| Ligno lime | 61 | 63* | 53 |
| Commercial calcitic lime | 58 | 55* | 51 |
| Dolomitic lime | 52 | 48 | 45 |
| Limestone (80% < 44μm) | NT† | 25 | 22 |

* Determined during the EPA LIMB Demonstration
† NT = Not tested

a comparable stoichiometry. This is thought to be due to the greater driving force the increased $SO_2$ concentration has on the reaction. A 5 to 7% absolute difference in $SO_2$ removal exists between 1.6 and 3.8% sulfur coal for any one sorbent at a stoichiometry of 2.0. While it might be argued that this difference is within the error limits of the calculations, the fact that it was consistently seen for all of the sorbents tested suggests that the effect is real. The removal efficiencies while burning the 3.0% sulfur coal fell approximately midway between the other two.

Figure 3 presents an example of the effect of coal sulfur content (inlet $SO_2$ concentration) on removal efficiency while injecting dolomitic lime at elevation 187 ft.

## Effect of Limestone Particle Size

Initial tests were run using a commercial limestone with a particle size distribution of 80% less than 44 μm. This limestone was chosen because it was representative of readily available material from commercial suppliers. While injecting this sorbent, removal efficiencies of about 22% were obtained at a stoichiometry of 2.0, while burning nominal 1.6% sulfur coal. $SO_2$ reductions of 30 to 35% had been expected with the limestone on the basis of pilot tests.[6,7] Possible reasons for this high a discrepancy, such as differences in porosity and surface area, were reviewed. The only variable that could easily be changed

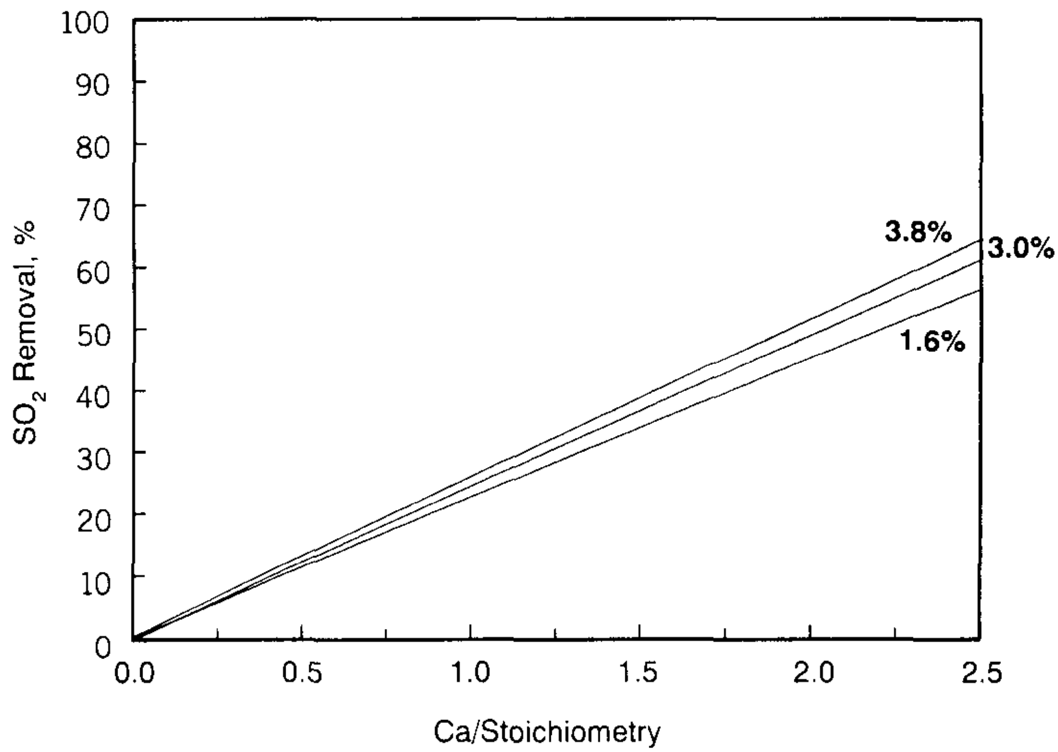


**Figure 3. Effect of coal sulfur ($SO_2$ concentration) on $SO_2$ removal while injecting dolomitic lime at elevation 187 ft.**

at full scale, however, was the fineness of the sorbent. With a grade of limestone in which all particles were less than 44$\mu$m in size, a removal efficiency of approximately 32% was achieved at a stoichiometry of 2.0. In order to determine what the upper limit in removal efficiency might be for calcitic limestone, an even finer limestone was then tested. This was the finest material available in truckload quantities and had a particle size distribution with virtually all particles less than 10 $\mu$m. It produced removal efficiencies on the order of 37 to 40% at the 2.0 Ca/S condition. Figure 4 presents $SO_2$ removal data for the three grades of limestone tested while injecting at the 181 ft boiler elevation and burning 1.6% sulfur coal.

## Effect of Injection Level

During the design phase of the EPA project, the optimum location for injection was identified as being on the front wall of the Edgewater furnace at elevation 181 ft where the

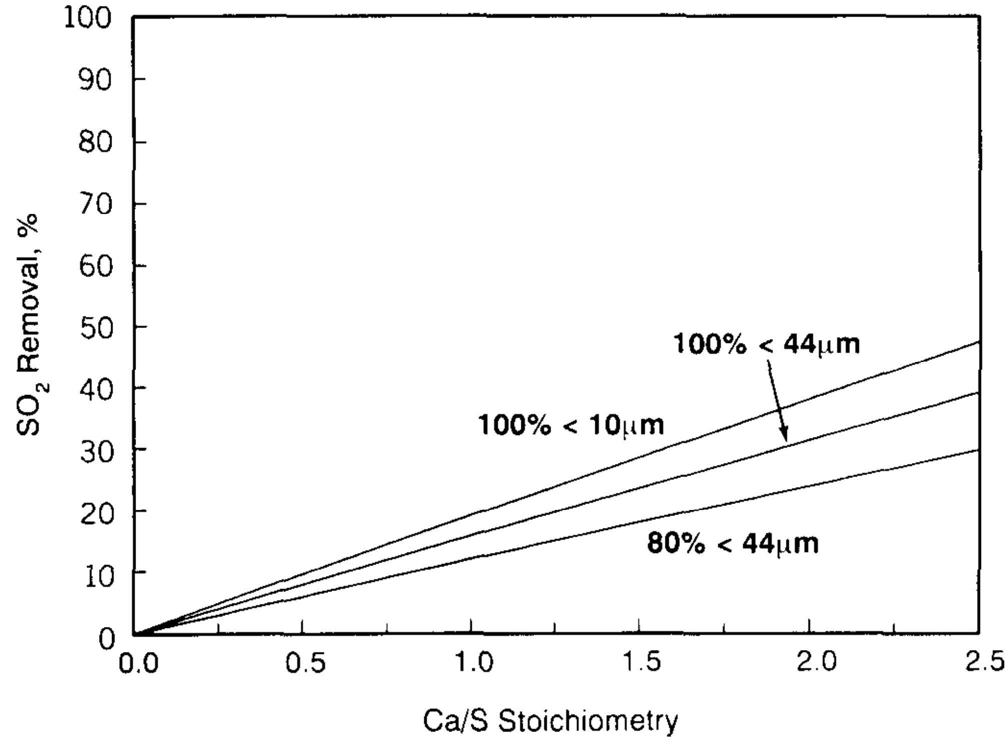


**Figure 4. Effect of limestone grind on $SO_2$ removal while burning 1.6% sulfur coal and injecting at elevation 181 ft.**

average temperature was expected to be approximately 2300F. This elevation corresponds to a level in this furnace just opposite the nose. Tests during the EPA LIMB Demonstration had indicated that injection at this level yielded higher $SO_2$ removal for the calcitic hydrated limes than injection at elevation 187 ft (injection at elevation 191 ft was not tested during the EPA project after a lower efficiency was obtained at elevation 187 ft). More intensive tests run during the LIMB Extension continued to show lower removal at the upper elevations, though the difference between elevations 181 and 187 was not as pronounced as had been seen earlier. An example of the differences in $SO_2$ removal achieved by the injection of dolomitic lime at levels 181, 187, and 191 ft is shown in Figure 5. The other sorbents exhibit similar behavior.

## Effect of Humidification

Most LIMB Extension testing was conducted with minimal humidification to approximately 275F for purposes of maintaining ESP performance. The humidification system was

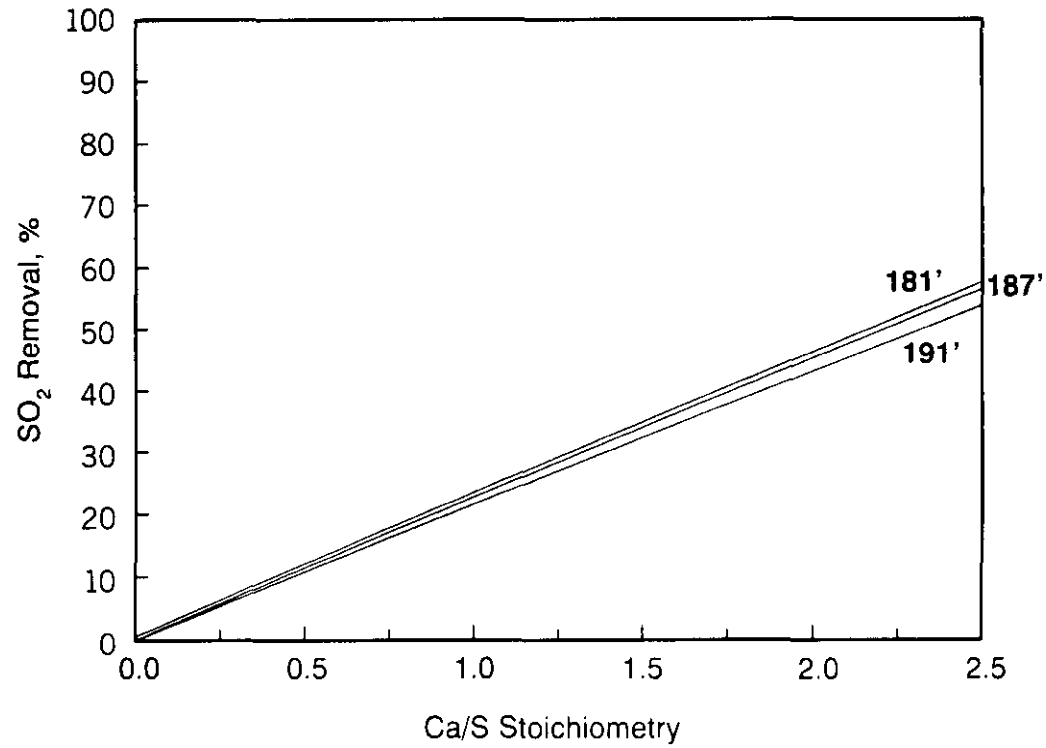


**Figure 5.** **Effect of injection level on $SO_2$ removal while burning 1.6% sulfur coal and injecting dolomitic lime.**

designed to achieve a 20F approach to the adiabatic saturation temperature of the flue gas (close approach) to permit demonstration of the Coolside process. This provided the opportunity to test the LIMB Process at close approach temperatures as well.

Close approach tests were run with the majority of the coal/sorbent combinations tested. The most extensive tests were run using the ligno lime sorbent injected at the 181 ft elevation while burning 1.6% sulfur coal. Table 3 shows the increase in efficiency predicted at the common reference condition for all the coal/sorbent combinations tested at close approach. The absolute increase in $SO_2$ removal efficiency resulting from close approach operation ranged from 7 to 17% for injection at a Ca/S ratio 2.0.

$NO_x$ Emissions

The DRB-XCL™ burners, installed as part of the initial LIMB demonstration, continued to operate and be evaluated during the LIMB Extension project. The overall average $NO_x$

**Table 3. Increase in absolute removal efficiency with humidification to close approach to saturation.***

| Sorbent | Nominal coal sulfur, wt % | | |
|---|---|---|---|
| | 1.6 | 3.0 | 3.8 |
| Calcitic hydrated lime | NT† | 10‡ | NT |
| Ligno lime | 17 | 9 | 10 |
| Dolomitic hydrated lime | 17 | 10 | NT |
| Limestone (80% < 44$\mu$m) | 7 | NT | NT |

* Sorbent injection at elevation 181 ft at a Ca/S ratio of 2.0
† NT = Not tested
‡ Determined during the EPA LIMB Demonstration

emissions during the demonstration was 0.43 lb/$10^6$ Btu. The plot of individual 10 min average outlet $NO_x$ emissions from April 1991 through August 1991 are presented in Figure 6. Emissions of 0.44 lb/$10^6$ Btu were calculated both for the 24 hr and 30 day rolling average values for the demonstration period. The emission rate did not appear to be sensitive to load conditions, although there appeared to be some variation within the scatter that might be controllable. In order to identify the source of the variation, attempts were made to correlate $NO_x$ emissions with load, flue gas $O_2$ concentration, pulverizers/burners in service, CO emissions, and coal fineness. Unfortunately, no consistent correlation was found between $NO_x$ emissions and any of these variables. Likewise, use of the $SO_2$ sorbents did not appear to have any effect on $NO_x$ emissions.

## Particulate Emissions

Humidification of the flue gas continued to be effective in maintaining the particulate emission control performance of the ESP during the DOE LIMB Extension. Opacity was generally in the 2 to 5% range during injection of each of the sorbents (compared to the plant opacity limit of 20%). This was similar to what had been observed during the EPA project. Only two differences were noted, the first being that the calcitic limestone did not seem to require as much humidification, either because its larger particle size made particulate collection easier and/or the fact that the cooler air heater outlet flue gas

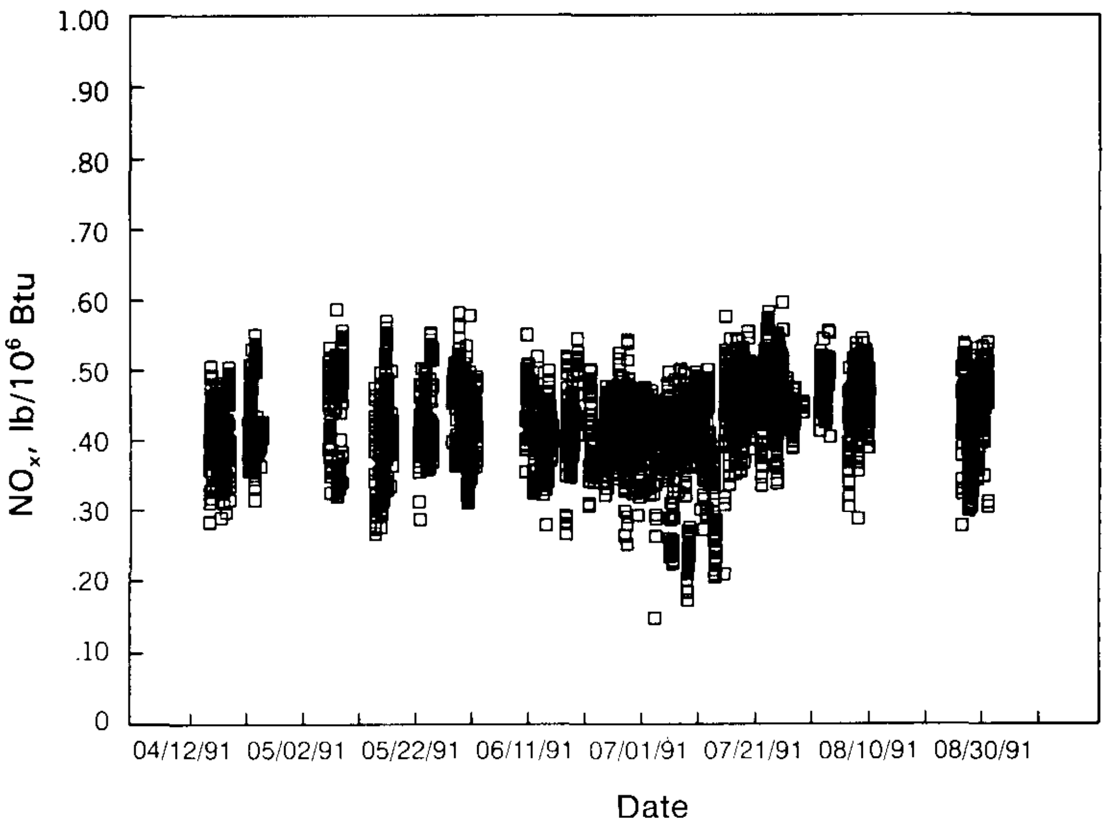


**Figure 6.** **10 min average DRB-XCL™ $NO_x$ emissions April 13, 1991 to August 30, 1991.**

temperatures required relatively little humidification water to maintain the temperature of the gas entering the ESP. The second difference occurred during use of the dolomitic lime which seemed to require a somewhat lower humidifier outlet temperature setpoint (250F versus 275F) to maintain the desired opacity.

## Operability and Reliability

The long term operability of the LIMB Process was demonstrated during LIMB Extension testing. The process was operated by the Edgewater Station personnel on a 24 hr/day basis, as required to support testing or to maintain stack emission requirements during periods in which high sulfur coal was burned in the furnace. As part of the overall assessment of the technology, operating time and downtime were recorded as indications of process and equipment availability. This data shows that the LIMB system was available about 95% of the time it was called upon to operate.

There were, however, a few operational aspects that became apparent due to the use of previously untested sorbents and/or more extensive tests. Probably the most notable of these was the limitation of the sootblowing system at the Edgewater facility. Prior to the LIMB Extension tests, the sootblowers were converted from compressed air to steam. This sootblower modification was undertaken in an effort to maintain a more normal air heater outlet temperature of about 300F, rather than the 350F temperatures seen during the EPA testing. After the conversion, the sootblowers could be cycled five to six times a shift, where it previously had been once or twice per shift. While the increased capacity helped somewhat at lower injection rates, the higher stoichiometric conditions still produced high outlet temperatures (up to a high of 375F for the dolomitic lime/3.8% sulfur coal combination at 2.0 Ca/S, a condition representing the highest sorbent mass feed rate). This suggests that the limitation was due not so much to the capacity of the sootblower system, but rather to the number and location of the sootblowers themselves. Since the temperatures appear to rise most dramatically in the vicinity of the primary superheater and economizer, additional sootblowers appear advisable in those areas.

Injection of the coarse (80% less than 44 $\mu$m) limestone sorbent into the furnace left the air heater outlet temperature almost unchanged at approximately 300F. This was unexpected in that more severe fouling had been anticipated. The phenomenon appears to be related to particle size, but no specific explanation has been identified at this point. The finer limestones tended to produce higher air heater outlet temperatures, though the data is limited since lesser total quantities of these materials were injected.

Another operational change noted during the LIMB Extension was in the area of waste handling and disposal. Here the effects of using either dolomitic lime or calcitic limestone were somewhat different than what had been found with the calcitic limes. The dilution of the ash by the unreactive MgO component of the dolomitic sorbent leads to increased ash loading and solids handling at the back end of the process. Since the MgO component does not hydrate appreciably at atmospheric pressure, this LIMB ash exhibited a lower level of steaming when water was added to the ash. The use of limestone, on the other hand, tended to produce greater quantities of steam during wetting of the ash in the unloading facility. This was due to the lower utilization of the sorbent for an equivalent injection stoichiometry.

## ECONOMIC ANALYSIS

With the successful completion of the LIMB and Coolside full scale demonstrations, the economic comparison of $SO_2$ removal with the LIMB, Coolside, and LSFO FGD technologies was made. A summary of the evaluation is presented here. The detailed comparison of the economics are presented in the final report.[5]

The evaluation is based on the capital and annual levelized costs for each of the three technologies. Technical and economic premises were developed utilizing the DOE Program Opportunity Notice (PON) DE-PS01-88FE61530, EPRI's *TAG™ Technical Assessment Guide*,[8] the design and operating experience from the LIMB project, Consol's topical report on the Coolside process,[4] and a review of state-of-the-art technology being utilized in the design of wet limestone FGD systems.

The goal of this analysis is to provide a comparison of the three FGD processes over the range of the economic and technical premises chosen. Direct comparisons of LIMB and Coolside with LSFO FGD must be interpreted with care. LSFO FGD is normally designed for high levels of $SO_2$ reduction, while the LIMB and Coolside processes were conceived as low capital cost technologies for moderate levels of $SO_2$ removal. In this analysis, LSFO FGD is assumed to be a technology that provides 95% $SO_2$ removal. LIMB and Coolside have been assumed to provide 60 and 70% $SO_2$ removal, respectively. For this reason, the comparison of annual levelized costs is performed on a \$/ton $SO_2$ removed basis.

### Basis of Evaluation

Similar technical and economic assumptions were used to provide as common a basis for the three fundamental process designs in order to make comparisons as valid as possible. Four reference plant capacities of 100, 150, 250, and 500 MWe were selected. Eastern bituminous coals were chosen which essentially differed only in that they had different sulfur contents of 1.5, 2.5, and 3.5% by weight. An economic evaluation, effectively consisting of a budgetary estimate targeted to be accurate to within 10 to 20%, was then made for each FGD process for each reference plant/coal sulfur combination. This resulted in 12 separate evaluations for each FGD process, or a total of 36 separate evaluations. Tables 4 through 6 outline the technical and economic assumptions used in determining costs.

## Costs

The cost analyses of the LIMB, Coolside, and LSFO FGD processes for each of the three coals and four plant sizes used the same overall approach. Whenever possible, this included

**Table 4. Reference plant design information.**

| | | | | |
|---|---|---|---|---|
| Plant location | Ohio, near the Ohio River | | | |
| Plant elevation | 500 ft above sea level | | | |
| Seismic zone | 1 | | | |
| Boiler type | Pulverized coal-fired, radiant boiler | | | |
| Capacity factor | 65% | | | |
| ESP: Emission rate | 0.1 lb/$10^6$ Btu | | | |
| Specific collection area | 400 $ft^2/10^3$ ACFM | | | |
| ID fans: LIMB | Adequate | | | |
| Coolside | Adequate | | | |
| LSFO | Supplemental fans required | | | |
| Plant retrofit factors: LIMB | 1.0 | | | |
| Coolside | 1.3 for the humidifier, 1.0 for other equipment | | | |
| LSFO | 1.3 | | | |
| Plant size, MWe (net) | 100 | 150 | 250 | 500 |
| Coal flow rate, lb/hr | 82,000 | 123,000 | 205,000 | 410,000 |
| Main steam flow, lb/hr | 634,000 | 951,000 | 1,585,000 | 3,170,000 |

a level of engineering typical of that used to provide actual budgetary estimates to customers in commercial applications. Although the number of cases examined precluded absolutely unique analysis of each, individual material balances established the basis for sizing and developing equipment lists. The reference plant and process design information established the basis for the scopes of equipment from which costs were individually determined. Whenever necessary, new vendor quotations were obtained to supplement the current B&W equipment cost data base which reflects costs on utility systems sold within the past year. Because it probably reflects the most widely accepted methodology, EPRI's *TAG*™ was used as a guide for the analysis, with vendor quotations or pertinent costs from the current data base being inserted whenever they were considered to be more representative than those from generic estimating techniques.

**Table 5. FGD process/equipment design assumptions.**

| | LIMB | Coolside | LSFO |
|---|---|---|---|
| $SO_2$ removal, % | 60 | 70 | 95 |
| Sorbent | Calcitic hydrated lime | Calcitic hydrated lime and soda ash | Limestone |
| Ca/S stoichiometry, mol Ca/mol S inlet | 2.0 | 2.0 | NA* |
| Ca/S stoichiometry, mol Ca fed/mol S removed | NA | NA | 1.05 |
| Na/Ca stoichiometry, mol/mol | NA | 0.2 | NA |
| Total system $\Delta P$, in WC | Negligible | 1.5 | 10 |
| ID fans | Adequate | Adequate | Supplemental fans required |
| Flue gas reheat | No | No | No |
| Flue gas bypass | NA | Yes, 100% | Yes, 100% |
| Isolation dampers | NA | 5 | 3 |
| New wet stack | No | No | Yes |
| Total sorbent storage, day | 7 | 7 | 31 |
| Waste product components | Fly ash, lime, gypsum | Fly ash, lime, calcium and sodium sulfites and sulfates | Disposable gypsum† |
| System outlet temperature, F | 275 | 145 | 125 |
| Total additional operating manpower required | 0 | 4 | 16 |

* NA = Not applicable
† As opposed to wallboard quality gypsum

**Table 6. Economic premises.**

| | LIMB | Coolside | LSFO |
|---|---|---|---|
| Reference date of cost estimate | April 1992 | April 1992 | April 1992 |
| Unit book life, yr | 15 | 15 | 15 |
| Tax life, yr | 15 | 15 | 15 |
| Levelizing factor for 15 yr carrying charges | 0.139 | 0.139 | 0.139 |
| Construction period, yr | 1 | 1 | 2-3 |
| <u>Indirect costs as percent of total direct capital</u> | | | |
| General facilities | 5 | 5 | 5 |
| Engineering | 10 | 10 | 10 |
| Project contingency | 18 | 18 | 15 |
| Process contingency | 5 | 5 | 2.5 |
| <u>Consumables, utilities, labor, and disposal costs</u> | | | |
| Water, $\$/10^3$ gal | 0.69 | 0.69 | 0.69 |
| Lime, $/ton delivered | 64 | 64 | NA* |
| Limestone, $/ton delivered | NA | NA | 17 |
| Soda ash, $/ton delivered | NA | 157 | NA |
| Sulfuric acid (93%), $/ton delivered | 102.40 | 102.40 | NA |
| Coal cost, $/ton | 34.09 | NA | NA |
| Replacement power, ¢/kWh | 5.8 | 5.8 | 5.8 |
| Steam, $\$/10^3$ lb | 6.19 | NA | NA |
| Solids disposal, $/ton (dry) | 9.26 | 9.26 | 9.43 |
| Fly ash credit, $/ton (dry) | 9.26 | 9.26 | NA |
| Labor rate, $/hr | NA | 23.15 | 23.15 |
| Land, $/acre | NA | NA | 7410 |

* NA = Not applicable

Costs are divided into the three major categories of capital cost, variable costs, and fixed operating and maintenance (O&M) costs. The capital costs, or total capital requirement (TCR), consists of the total plant investment (TPI), preproduction costs, inventory, land, and interest during construction. Variable costs include major consumables and disposal costs.

Maintenance costs for both labor and materials, operating manpower costs, and administrative and overhead costs constitute the fixed O&M costs. Annual levelized requirements, expressed in terms of \$/ton $SO_2$ removed and operating costs, expressed in terms of mill/kWh, were also determined. A constant dollar levelization technique, as outlined in *TAG™*, negates the effect of inflation on the capital carrying charges and operating costs. The costs for consumables, utilities, labor and disposal were derived from *TAG™* and converted to 1992 dollars.

Comparison of LIMB, Coolside, and LSFO FGD Economics

The comparison of LIMB, Coolside, and LSFO FGD capital and annual levelized costs are summarized in Tables 7 and 8, respectively, for each of the 36 cases evaluated. Increasing coal sulfur content from 1.5 to 2.5 to 3.5% results in an increase in capital costs. Total capital required is expressed on a \$/kW basis. The annual levelized cost, calculated in terms of \$/ton $SO_2$ removed with a basic assumed book life of 15 yr, accounts for the operating and maintenance costs associated with each case. The first year operating costs, calculated on a mill/kWh basis, are shown in Table 9 for both fixed and variable costs.

The results were analyzed and compared to determine the economic applicability of each process. On a \$/kW basis, the installed capital cost of the LSFO FGD process was found

**Table 7. Capital cost comparison, \$/kW.**

| Coal Sulfur, wt % | LIMB | Coolside | LSFO | LIMB | Coolside | LSFO |
|---|---|---|---|---|---|---|
| | 100 MWe | | | 150 MWe | | |
| 1.5 | 93 | 150 | 413 | 66 | 116 | 312 |
| 2.5 | 95 | 154 | 421 | 71 | 122 | 316 |
| 3.5 | 102 | 160 | 425 | 73 | 127 | 324 |
| | 250 MWe | | | 500 MWe | | |
| 1.5 | 46 | 96 | 228 | 31 | 69 | 163 |
| 2.5 | 50 | 101 | 235 | 36 | 76 | 169 |
| 3.5 | 54 | 105 | 240 | 40 | 81 | 174 |

to be about 2.5 times higher than that of the Coolside process, and about 4.8 times higher than the LIMB process. The installed capital cost of the Coolside process was found to be about 1.9 times higher than the LIMB process.

On a \$/ton of $SO_2$ removed basis, the annual levelized costs showed that Coolside was economically favored over LSFO FGD for plant sizes up to about 500 MWe (net), while burning 1.5% sulfur coal, up to 220 MWe while burning 2.5% sulfur coal, and up to 100 MWe while burning 3.5% sulfur coal.

**Table 8. Annual levelized cost comparison, \$/ton $SO_2$ removed*.**

| Coal Sulfur, wt % | LIMB | Coolside | LSFO | LIMB | Coolside | LSFO |
|---|---|---|---|---|---|---|
| | 100 MWe | | | 150 MWe | | |
| 1.5 | 791 | 943 | 1418 | 653 | 797 | 1098 |
| 2.5 | 595 | 706 | 895 | 520 | 624 | 692 |
| 3.5 | 525 | 629 | 665 | 461 | 570 | 527 |
| | 250 MWe | | | 500 MWe | | |
| 1.5 | 549 | 704 | 831 | 480 | 589 | 623 |
| 2.5 | 456 | 567 | 539 | 416 | 502 | 411 |
| 3.5 | 419 | 526 | 413 | 392 | 482 | 321 |

* 15 yr book life assumed

LIMB was economically favored over LSFO FGD for all plant sizes while burning 1.5% sulfur coal, up to 450 MWe while burning 2.5% sulfur coal, and up to 240 MWe while burning 3.5% sulfur coal.

LIMB was economically favored over Coolside for all the cases compared.

Cost sensitivity analyses were also undertaken to determine the effects of certain economic variables on costs. It was determined that decreasing the plant capacity factor favored the LIMB and Coolside processes, as did decreasing the book life of the plant. Varying the reagent costs had a greater effect on LIMB and Coolside economics, while having only a moderate effect on the LSFO FGD process economics.

**SUMMARY AND CONCLUSIONS**

The demonstration of the generic applicability of LIMB technology, coupled with similar success with Coolside technology, more than met the project's objective of building upon the knowledge base gained during the original EPA LIMB demonstration. The successful completion of the full-scale demonstrations of the two sorbent injection technologies provides low capital cost alternatives to conventional wet FGD systems.

The Coolside demonstration was successful in characterizing the resultant $SO_2$ emissions while injecting two different calcium-based sorbents while burning high sulfur coal. The short term operability of the Coolside process was demonstrated and the necessary equipment design changes required for a commercial installation were developed.

With regard to the LIMB process, system operation succeeded in characterizing performance of the four sorbents, while three coals with sulfur contents of 1.6, 3.0, and 3.8% were burned in the boiler. The sorbents tested were commercial calcitic hydrated lime, the same lime with a small amount of calcium lignosulfonate added, a "type-N" atmospherically hydrated dolomitic lime, and pulverized calcitic limestone at three increasingly finer grinds. With the exception of the limestone/3.8% sulfur coal, all the basic coal/sorbent combinations were tested between the original LIMB Demonstration and the LIMB Extension projects. Tests with this one combination were not attempted because the relatively low $SO_2$ removal efficiency of this sorbent would have made it unnecessarily difficult to obtain data within a reasonable time period, and still maintain compliance with the plant's 30-day weighted rolling average $SO_2$ emission limit of 3.4 $lb/10^6$ Btu.

The economics of flue gas desulfurization by the LIMB, Coolside, and LSFO FGD technologies were determined in the form of budgetary cost estimates for 12 cases each. Process designs were based on optimized, commercial, retrofit installations with assumed

**Table 9. First year operating costs, mill/kWh**

| Coal Sulfur, wt % | LIMB | Coolside | LSFO | LIMB | Coolside | LSFO |
|---|---|---|---|---|---|---|
| Fixed Operating Costs* | | | | | | |
| | 100 MWe | | | 150 MWe | | |
| 1.5 | 0.68 | 1.57 | 4.37 | 0.48 | 1.16 | 3.18 |
| 2.5 | 0.69 | 1.58 | 4.42 | 0.51 | 1.20 | 3.20 |
| 3.5 | 0.73 | 1.61 | 4.45 | 0.51 | 1.22 | 3.26 |
| | 250 MWe | | | 500 MWe | | |
| 1.5 | 0.33 | 0.89 | 2.20 | 0.22 | 0.60 | 1.42 |
| 2.5 | 0.35 | 0.91 | 2.24 | 0.25 | 0.64 | 1.45 |
| 3.5 | 0.37 | 0.93 | 2.28 | 0.27 | 0.66 | 1.49 |
| Variable Operating Costs† | | | | | | |
| | 100 MWe | | | 150 MWe | | |
| 1.5 | 2.82 | 2.38 | 2.11 | 2.67 | 2.85 | 2.02 |
| 2.5 | 4.30 | 4.80 | 2.72 | 4.15 | 4.77 | 2.56 |
| 3.5 | 5.81 | 7.11 | 3.29 | 5.66 | 7.09 | 3.19 |
| | 250 MWe | | | 500 MWe | | |
| 1.5 | 2.54 | 2.81 | 1.94 | 2.51 | 2.77 | 1.86 |
| 2.5 | 4.03 | 4.75 | 2.51 | 3.99 | 4.70 | 2.41 |
| 3.5 | 5.52 | 7.05 | 3.12 | 5.49 | 7.02 | 2.98 |
| Total Operating Costs | | | | | | |
| | 100 MWe | | | 150 MWe | | |
| 1.5 | 3.50 | 4.45 | 6.48 | 3.15 | 4.01 | 5.20 |
| 2.5 | 4.99 | 6.38 | 7.14 | 4.66 | 5.97 | 5.76 |
| 3.5 | 6.54 | 8.72 | 7.74 | 6.17 | 8.31 | 6.45 |
| | 250 MWe | | | 500 MWe | | |
| 1.5 | 2.87 | 3.70 | 4.14 | 2.73 | 3.37 | 3.28 |
| 2.5 | 4.38 | 5.66 | 4.75 | 4.24 | 5.34 | 3.86 |
| 3.5 | 5.89 | 7.98 | 5.40 | 5.76 | 7.68 | 4.47 |

* Includes operating labor, maintenance labor and material, and administration and overhead
† Includes reagents, power, water, and steam usage, and waste disposal costs

$SO_2$ removal efficiencies of 60, 70, and 95%, respectively. The basic set of reference plants were assumed to burn 1.5, 2.5, and 3.5% sulfur coal in units of nominal 100, 150, 250, and 500 MWe capacities. Comparisons made included those of capital costs on a $/kW basis, operating costs on a mill/kWh basis, and annual levelized costs on a $/ton $SO_2$ removed basis. Sensitivities of the economics to capacity factor, book life, and reagent cost were determined for all three processes.

Finally, the economic analyses reveal that further optimization of the technologies should focus on improving sorbent utilization. Such studies are in progress, notably within laboratories at EPA, several universities under sponsorship of the OCDO, the Illinois Clean Coal Institute (formerly the Center for Research on Sulfur in Coal), and private industry. Advances in these technologies will provide more cost effective options for older, smaller plants to reduce $SO_2$ emissions simply and reliably.

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## LEGAL NOTICE/DISCLAIMER

# Recovery Scrubber Installation and Operation

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ABSTRACT

The Passamaquoddy Technology Recovery Scrubber™ Innovative Clean Coal Technology Program project at the Dragon Products Company Inc. plant in Thomaston, Maine is explained, covering the technology, the project goals and participants, innovative aspects of the technology, and current project status. Performance of the technology and market potential are also discussed.

## OVERVIEW

### The Technology

The Passamaquoddy Technology Recovery Scrubber™ technology is a wet flue gas desulfurization process that uses waste alkaline materials (fly ash, cement kiln dust, incinerator ash, biomass ash) as reagent and produces useful by-products that minimize or eliminate the need for disposal or landfilling of waste. In many applications the process will provide net operating income.

The Recovery Scrubber process was selected under Round 2 of the Innovative Clean Coal Technology Program.

### Goals of the Project

Project goals were to design; build; operate and demonstrate the new Recovery Scrubber technology on a coal fired wet process cement manufacturing kiln; to eliminate landfilling of waste cement kiln dust, a waste product of cement manufacture; and to significantly reduce emission of flue gas sulfur dioxide from combustion of coal. Further goals are to assess the environmental and economic performance of the process.

### The Project Participants

The project participants are:

The U.S. Department of Energy, Pittsburgh Energy Technology Center;

Passamaquoddy Technology L.P., owner of the technology;

Dragon Products Company Inc., a subsidiary of CDN U.S.A. and the host site providing partial funding of the installation.

## BASIC INFORMATION

### Location

The project is located in Thomaston, Maine at the Dragon Products Company Inc. cement plant which is owned by CDN U.S.A. The area is a scenic Maine coastal town, heavily dependent on tourist trade and on remaining a scenic coastal community, where control of environmental pollution is of vital interest to both the State of Maine and local residents. The host plant is also located up wind from a Class 1 area in Acadia National Park and is regulated accordingly.

## Project Cost

The project is currently in Phase III, the Operating Phase, and will continue in the Operating Phase for several months. Final project cost is, therefore, not yet available. The cost to date is approximately $16 million. Total cost will exceed $16 million when all project related costs associated with the operating period are determined.

## Project Duration

Construction began in April of 1990 (earthwork related to clearing the site began in the fall of 1989). The process was first operated nine months later on December 21, 1990. After system debugging and process modifications the operating period began on August 20, 1991 and will run for a period of 13 operating months. The operating period will include only that time during which the system is actually in operation. The cement plant has been shut down for one long, and several short, maintenance or inventory plant outages. Therefore completion of the operating period will require more than 13 consecutive calendar months.

## Project Disposition

After completion of Phase III the project will continue to be operated by Dragon Products Company Inc. as the waste cement kiln dust and sulfur dioxide control system.

# DESCRIPTION OF THE TECHNOLOGY

## General Information

The Recovery Scrubber process uses alkaline waste materials as scrubbing reagent. These may include fly ash, waste cement kiln dust, incinerator ash, biomass ash from wood fired systems, and other similar wastes. Wastes may be used in solid or liquid form. Use of these wastes has the advantage of being low cost reagent, or of providing income from tipping fees for consumption of waste. It also has the advantage of reducing, or in some cases eliminating, the volume of waste that must enter a landfill, thereby conserving valuable landfill space. Figure 1. illustrates the basic process flows and system components.

The alkali metals sodium or potassium, rather than the alkaline earth metals calcium or magnesium, are used for combination with sulfur from flue gas. Calcium will form calcium sulfate (gypsum or anhydrite) or calcium sulfite when reacted with oxidized sulfur from flue gas. These compounds can cause "gypsum scaling" in scrubber systems or a difficult to de-water and dispose waste sludge. Sodium or potassium, on the other hand, form soluble compounds with flue gas sulfur or hydrochloric acid, that is, potassium sulfate, potassium chloride, sodium sulfate, or sodium chloride. They will not cause gypsum scaling, and both potassium sulfate and potassium chloride are highly valued marketable by-products. Sodium sulfate and sodium chloride are marketable products also, but of lower value.

Calcium present in the waste will react to form calcium carbonate (limestone) from carbon dioxide in the flue gas. This includes calcium present in the waste as calcium oxide, calcium hydroxide, or calcium sulfate. This results in scrubbing of carbon dioxide from the flue gas. The resulting product, calcium carbonate, makes the spent reagent useful as raw material for use in cement manufacture or as starting material for manufactured aggregate for use in asphalt or concrete, thus eliminating the need to dispose of spent material in a landfill. Both the environmental advantage and the cost advantage of producing a useful by-product rather than a waste sludge are important.

Waste heat from the flue gas being scrubbed is recovered and used in the Recovery Scrubber process. Heat that would normally be released up the smokestack is not wasted. Recovery of the waste heat allows for economical recovery of the soluble alkali sulfate salts from solution.

Recovered alkali sulfate salts are removed from the process as solid salt crystals of potassium sulfate or sodium sulfate. In situations where chloride is present in the waste used as reagent, or in the flue gas being scrubbed, the product will include potassium chloride and/or sodium chloride. The various salts produced can be separated to enhance their resale value. All of these products have resale value. Potassium sulfate has the highest value at $200 per ton wholesale or up to $400 per ton retail.

## INNOVATIVE ASPECTS OF THE PROJECT

There are several innovative features of the Recovery Scrubber Technology. As a high efficiency flue gas scrubbing system that seeks to minimize waste and turn operating cost of pollution control into operating profit, it is necessary to use new solutions to old problems throughout.

1. Use of Waste
   Use of waste rather than purchased raw material is a different approach. Because consumption of waste may provide a tipping fee the economic impact of income vs. cost for reagent is obvious.

2. Use of Alkali Metals

Use of potassium and/or sodium as the reactive chemical species for combination with flue gas sulfur provides several benefits. As noted above production of gypsum sludge is eliminated. Potassium and sodium can be easily separated from the calcium carbonate, silica, alumina, and iron compounds remaining after use as scrubbing reagent. Recovery of the potassium and sodium allows their sale into a high value market, but it also means that the remaining material is essentially free of potassium and sodium and is therefore useful, rather than requiring disposal as waste containing leachable caustic compounds.

3. Soluble Scrubber Reaction Products
Use of soluble compounds formed from scrubbing reaction products, rather than insoluble precipitates eliminates fouling of the scrubbing equipment and allows easy recovery of the soluble materials for their market value.

4. Waste Heat Use
Use of waste heat recovered from flue gas provides a cost effective means of preventing release of pollutants to area water bodies as well as a means of recovering valuable salts and distilled water from dilute solution. The waste heat recovered may be from low grade or high grade sources. It is possible to use waste heat remaining in the flue gas after use of most of the heat for kiln processes, or in boiler applications. Because recovery of waste heat and efficient flue gas scrubbing are combined in one integrated process it is possible to release to the atmosphere relatively low temperature flue gas that has been cleansed of most of its noxious gases and, therefore, requires no reheat.

5. Tray Type Reactor
Use of a tray reactor is not common in a flue gas desulfurization system of this size because the cost of operation is higher than similarly sized dry scrubbing or lime/limestone spray systems. However, the tray reactor is necessary for maintenance of the specific chemical environment in the process, and the positive overall economics of the scrubbing system more than compensate for the small added forced draft fan operating cost.

6. Beneficial Reuse of Spent Reagent
Spent reagent from scrubbers is a major disposal problem in some areas and will become a major problem in most areas eventually. The potential reagent input to the Recovery Scrubber, that is, fly ash, cement kiln dust, incinerator ash, and biomass ash are all suitable as raw material feed for a cement kiln after being used in the scrubber process. This process, therefore, has the potential to produce no landfilled waste at all in many applications. There will always be some applications too

far from cement processing plants to make transport economical, or where a potential user is second or third in line to offer kiln feed to a cement plant. In those situations, because deleterious alkali metals have been removed, it is possible to use the spent reagent as raw material for manufactured asphalt or concrete aggregate.

7. Elimination or Reduction of Landfilling
   Landfilling of waste from scrubbing systems is the rule rather than the exception. What follows from the above discussion of 1. Use of Waste and 6. Beneficial Reuse of Scrubbing Reagent, is the reduced need to dispose of materials in landfills.

## HISTORY OF THE TECHNOLOGY DEVELOPMENT

The Dragon Cement Company plant uses coal, as do most cement kilns, and emits sulfur dioxide. The plant also produces waste cement kiln dust as baghouse catch from the flue gas stream. Most cement plants also produce cement kiln dust although it may be captured by electrostatic precipitators as well as baghouses. Cement kiln dust contains partially calcined limestone and the oxides of sodium and potassium. These materials, when wet, will yield a basic (high pH) solution. Waste cement kiln dust is classified as waste because of the presence of the oxides of sodium and potassium. In some cases it is waste because of the presence of chloride or sulfate as well. If these contaminants could be removed the remainder of the material, principally silica, limestone, alumina, and iron oxide, could be returned to the cement kiln as raw material. Leaching of these salts has been tried with very limited success because mixing water with cement kiln dust induces a setting reaction and the mixture becomes unworkable.

The flue gas emitted from cement kilns is acid. The typical constituents of the flue gas, carbon dioxide, sulfur dioxide, and nitrogen oxides will produce acids when mixed with water.

The author noted that combining the two wastes, in water, would allow the caustic solid to neutralize the acid gas. In addition the water would dissolve the products of the reaction so that cement kiln dust could be returned to the kiln free of alkalis and chloride or sulfate. Further evaluation showed that the waste heat leaving the kiln in the flue gas was of sufficient quantity to provide the necessary energy for boiling away water to yield the solid crystalline potassium sulfate product.

The process was first tried at laboratory scale using small samples of waste cement kiln dust and flue gas extracted from the kiln exhaust stream. Results were promising and so a pilot scale facility was built. It was connected to the cement plant waste dust handling system to extract a "run of process" stream that would be representative of normal operation. Flue gas was collected from the stack and added to the process. The pilot plant operated for six months providing detailed information on the chemistry of starting, intermediate, and finished materials, and the flow rates, temperatures, etc. to be used for design of the full scale process.

At the time of this research the cement plant was owned by the Passamaquoddy Indian Tribe of Maine. Review of the process by a number of experts from industry and academia indicated that it was worth pursuing. Building the first full scale installation, however, would be expensive and, as new technology, a considerable risk.

We became aware, through friends in the engineering business, of the Program Opportunity Notice issued by the U.S. Department of Energy for Round Two of the Innovative Clean Coal Technology Program. It was clear to us that the ICCTP was the right program at the right time. It has also turned out to be the right people. The Program is enabling. It fills the gap between what industry can risk and what is needed to bring a new, innovative, risky, unknown, untried, but extremely valuable and useful technology to a state of commercial readiness. We applied, were selected, and the program has seen us through to where we are today.

The technology is important because it is a significant advance in affordable pollution control. The demonstration project is important because it either would not have been done without the ICCT program, or it would have taken much longer and very likely, because of cost, have ended in failure.

## INSTALLATION OF THE TECHNOLOGY

The scrubbing process was installed with minimal impact on the operating cement plant. It is an "end of the pipeline" retrofit process. The only interconnect to the cement plant that might have curtailed operation is the physical tie in of the flue gas handling duct. The cement plant must shut down periodically for replacement of kiln brick. The tie in was made during a routine shut-down with no impact on kiln operation.

The Recovery Scrubber operates as an integrated unit, therefore, all subsystems in the process were operable at the outset with the exception of the crystalline product pelletizing equipment which was not necessary for operation.

The process control system is by computer with operator interface and ability to override as necessary. The control panel and display are located on the desk of the cement plant kiln operator for his use. No additional operator is necessary.

## TEST PLAN

Testing of performance has included EPA Method # 5 and Method # 6 for compliance with State and Federal regulations. Measurements included before and after (upstream and downstream) determination of sulfur dioxide, nitrogen oxides, and particulate. Testing also includes online continuous monitoring of sulfur dioxide and nitrogen oxides by the cement plant for reporting to and compliance with State regulations.

Sulfur dioxide removal efficiency has been in the 90 to 92 percent range with some long periods of 95 percent removal. Nitrogen oxide removal efficiency has been variable at between 5 percent and 15 percent. Particulate removal efficiency was only measured during the formal stack testing. The grain loading was 0.006 grains per standard cubic foot, which is as good as or better than electrostatic precipitator or baghouse performance.

Additional testing has been done on the processed cement kiln dust and its suitability for use as raw material in the cement plant. There have been occasions during start-up and optimization where the efficiency of removal of potassium and/or sulfate has been lower than desired. Adjustments in process flows have brought the $K_2O$ and $SO_4$ levels to within design specifications.

## MARKET POTENTIAL

The overall market potential for this technology is quite large. Because it is applicable to a variety of fossil fuel or waste fired facilities it can impact a number of industries. The first market is likely to be the cement industry. Cement is the industry where it was first developed and applied and so has had the most visibility to date. The U.S. market covers approximately 100 cement plants and 200 cement kilns. Canada and Mexico add approximately another 100 plants. The rest of the world is more of a question because in the new eastern European countries the state of the industry and conditions of kiln size and existing pollution control is not well understood. Non- North American cement plants will probably add an additional 500 kilns to the total market.

The second is probably going to be the pulp and paper industry where it offers even greater operating economic benefit. There are approximately 10 times as many pulp and paper mills as there are cement plants in the world. However, less than half will be really excellent candidates for the technology because of lack of sufficient waste reagent.

A third industry will be waste to energy or waste incineration. The size of the market is currently small but continues to grow as waste burning is adopted as the solution to large volumes of municipal waste.

Passamaquoddy Technology L.P. intends to pursue marketing in cement, pulp and paper, and waste to energy vigorously.

Other markets, potentially larger than all of the above mentioned, exist. Any manufacturing process which uses fossil fuel or waste fuel could use the process. This includes power generation where boilers are 200 to 300 MW or less in size and use coal as fuel. It also includes any other boiler systems.

# DEMONSTRATION OF THE UNION CARBIDE CANSOLV™ SYSTEM PROCESS AT THE ALCOA GENERATING CORPORATION WARRICK POWER PLANT

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## ABSTRACT

Union Carbide's CANSOLV™ System for the removal of $SO_2$ from gas streams utilizes a thermally regenerable organic amine as the absorbent in a recovery-type $SO_2$ scrubbing process. Countercurrent multi-stage in-duct scrubbing, utilizing air atomizing nozzles, takes advantage of the absorbent's fast reaction with and high capacity for $SO_2$ to effect up to 99% removal in a very compact and energy-efficient manner. The process produces minimal effluents, unlike conventional limestone-based processes, which require dedicated landfill sites for the waste by-product.

The CANSOLV™ System process was successfully tested at a pilot plant capable of treating 10,000 $m^3$ (6000 ACFM), equivalent to 2 MWe. An $SO_2$ removal rate of greater than 95% was achieved at low L/G ratios at scrubber residence times of less than 1 second, and at a pressure drop of 15 mm Hg (8" WC). The results confirm that the CANSOLV System is economically superior to the advanced wet limestone FGD processes, while delivering other benefits, such as small footprint, higher $SO_2$ removal and energy efficiency.

The United States Department of Energy (DOE) has selected Union Carbide's CANSOLV System, under Round IV of the Clean Coal Technology program, for negotiation of a DOE Cooperative Agreement. The CANSOLV System is planned to be installed, as a joint project with the Aluminum Company of America, at the Alcoa Generating Corporation Warrick plant at Newburgh, Indiana. A 75 MWe equivalent flue gas stream will be scrubbed for the removal of $SO_2$ produced by the burning of 3.4% sulfur coal. The demonstration facility is scheduled to commence operations in 1995, and is expected to demonstrate the economic superiority of the CANSOLV System at commercial scale.

## INTRODUCTION

The last 20 years have been a time of substantial progress in the control of sulfur dioxide emissions resulting from the burning of sulfur-bearing fuels and from industrial processes. The Clean Coal Technology (CCT) program has contributed to this progress by supporting the development of new Flue Gas Desulfurization (FGD) technologies.

The dominant desulfurization technology today is limestone or lime-based processes in various forms. While in general reliable and, in some forms, capable of high $SO_2$ removal efficiency, they produce large quantities of low-value waste products, are expensive to build and operate, and are difficult to retrofit in constrained sites due to the large equipment size. With increasing concern over the cost and availability of landfill sites and public demand for resource recovery and recycling, recovery-type $SO_2$ removal processes are becoming increasingly desirable. To meet this need, Union Carbide has developed the CANSOLV™ System, a regenerable $SO_2$ removal process that utilizes a novel regenerable absorbent.

Most $SO_2$ removal absorbents, with the exception of sodium sulfite solutions, undergo a reaction with $SO_2$ that is essentially irreversible under absorber conditions. Consequently, such absorbents are inherently undesirable for recovery processes, since the energy or chemical requirement for regeneration is high.

By contrast, a recovery process requires an absorbent which is reversible under normal operating conditions. Such an absorbent must have a desirable balance of $SO_2$ absorption and desorption tendencies to minimize the total operating and capital costs, while meeting or exceeding environmental requirements. Up to now, commercially available regenerable processes have not been able to meet these demanding requirements. The CANSOLV™ System, however, achieves these goals, primarily by the use of a novel absorbent, UCARSOL® Absorbent LH.

UCARSOL Absorbent LH is a proprietary product consisting primarily of an aqueous amine solution. It is a homogeneous liquid throughout the process cycle and exhibits no tendency to precipitate solids. This has several benefits:

- No equipment erosion
- Small absorber size possible because of rapid mass transfer
- No scaling
- No solids handling

The absorbent is non-volatile, stable both thermally and oxidatively under process conditions, and has been designed to meet all applicable health and safety standards.

## PROCESS CHEMISTRY

Because of technical simplicity, aqueous scrubbing/regeneration cycles have been the basis of most commercial regenerable FGD processes, such as the sodium sulfite process. In aqueous media, dissolved $SO_2$ undergoes reversible hydration and ionization reactions that can be summarized as:

$$SO_2 + H_2O \rightleftharpoons H_2SO_3 \qquad (1)$$

$$H_2SO_3 \rightleftharpoons H^+ + HSO_3^- \qquad (2)$$

$$HSO_3^- \rightleftharpoons H^+ + SO_3^= \qquad (3)$$

The dissolution or equilibrium constants for steps (2) and (3) are reported as $1.54 \times 10^{-2}$ and $1.02 \times 10^{-7}$ at 18°C in dilute aqueous solution[1]. The scrubbing capacity of water can be increased by adding a buffer or base to the absorbent, which consumes hydrogen ions and causes reactions (1) - (3) to shift to the right.

Steam-stripping regenerative processes, in which the bases used are stronger than sulfite, degenerate to a sulfite/bisulfite scrubbing cycle, i.e. the effective base is sulfite.

$$2\ NaOH + SO_2 \rightarrow Na_2SO_3 + H_2O \qquad (4)$$

$$Na_2SO_3 + SO_2 + H_2O \rightleftharpoons 2\ NaHSO_3 \qquad (5)$$

Reaction (4) occurs in the initial contact of the base with $SO_2$. Reaction (5) is the basis for scrubbing, being shifted towards the right in the absorber and being reversed by high temperature in the regenerator.

The sodium ion does not participate in the reaction, its role being to provide electrical neutrality to the solution. Reaction (5) can then be restated as (6), in order to highlight the essential process.

$$SO_3^= + SO_2 + H_2O \rightleftharpoons 2\ HSO_3^- \qquad (6)$$

Any soluble cation can be used, as is sodium in the sodium sulfite process, or a protonated amine (the triethanolammonium ion) in the UCAP process[2]. The exact structure of the CANSOLV™ System amine absorbent is proprietary.

The scrubbing/stripping reaction can be represented as:

$$R_2 - \underset{\underset{R_3}{|}}{\overset{\overset{R_1}{|}}{N}} + SO_2 + H_2O \rightleftharpoons R_2 - \underset{\underset{R_3}{|}}{\overset{\overset{R_1}{|}}{N^+}} - H + HSO_3^- \qquad (7)$$

The amine absorbent of the CANSOLV™ System combines a low molecular weight and high concentration, resulting in a net removal of 25-100 g $SO_2$/liter (0.2 - 0.8 lb. $SO_2$/USG), depending on the inlet $SO_2$ concentration, scrubbing temperature and % $SO_2$ removal desired.

The rate of $SO_2$ absorption into limestone slurries is limited by the slow dissolution of limestone, which can only be partly controlled by limestone grind fineness and slurry pH.

Since the CANSOLV System, as represented by Equation (7), is essentially an acid-base reaction in a concentrated, homogeneous medium, its rate of reaction is very high. The limitation to mass transfer then becomes the gas-side resistance, which can be minimized by proper scrubber design.

The high $SO_2$ capacity of the CANSOLV System absorbent and its high reactivity eliminate the need for absorbent recycle in the scrubber and permit operation at very low L/G ratios.

Practical $SO_2$ absorbents must be nonvolatile in order to prevent equilibrium vapor phase losses with the flue gas. The aromatic amines of the "Sulphidine" and "Asarco" processes exhibit significant volatility and require removal from the treated flue gas stream by washing with dilute sulfuric acid[3]. This is both costly and complicated. The absorbent of the CANSOLV System is essentially nonvolatile - its vapor pressure is less than 25 ppb ($1.9 \times 10^{-7}$ mmHg) at normal scrubbing temperatures.

Due to the special nature of the CANSOLV System absorbent, strong acids, which either form in or are captured by the amine as heat stable salts, may be present at high concentrations without limiting the amine solution's scrubbing capacity.

Heat stable salts form by reaction of the amine absorbent with acids that are either nonvolatile or too strong to be driven off in the steam regeneration step. These acids are introduced into the absorbent from the following sources:

1. Flue gas - may contain $SO_3$ (produces $H_2SO_4$), HCl, HF, and $NO_2$.
2. $SO_2$ oxidation to $SO_3$ by oxygen.
3. Disproportionation of sulfite to sulfate and other sulfur species:

$$SO_3^{=} \rightarrow SO_4^{=} + \text{other sulfur species} \qquad (8)$$

Many other reactions that produce strong acids are described in Reference 4.

## PROCESS FLOW

The CANSOLV™ System flow diagram is shown in Figure 1. The seven major process steps are:

1. Gas Cooling - The gas feed to the CANSOLV System would normally be after the ESP (electrostatic precipitator) or other particulate-removal equipment. If heat recovery is economically justified in a particular site, this could be accomplished by condensing heat exchange. The recovered heat can be used for gas reheat, combustion air preheat, etc. Condensate from any condensing heat exchangers would drain into the prescrubber.

2. Prescrubber - Air-atomizing water-spray nozzles saturate the feed gas and remove $SO_3$, chlorides, fluorides, $NO_2$, and some of the remaining particulate.

3. Scrubber - The absorption of $SO_2$ from the gas is effected in a countercurrent mass-transfer scrubber. The absorbent is sprayed into the flue gas stream by air-atomizing nozzles. Due to the high reactivity of the absorbent, the $SO_2$ is rapidly removed in a relatively short length of ducting. This enables the CANSOLV System scrubber to operate at high gas velocities (up to 10 m/s or 35 ft/s). The absorbent droplets are removed from the gas stream between mass-transfer stages by mist eliminators, and again, after the final scrubbing stage, by high-efficiency mist eliminators. Using this method, absorbent recovery on the order of 99.995% has been demonstrated. Any remaining particulate and strong acids are also scrubbed from the gas. Energy requirements for scrubbing are low due to the very low liquid/gas ratio made possible by the high $SO_2$ capacity of the absorbent and the low pressure drop in the scrubber.

4. Regeneration - The rich ($SO_2$-containing) absorbent is pumped to the regeneration tower via a filter and a lean-rich absorbent heat exchanger. The regenerator is similar in design to regenerators in alkanolamine gas sweetening service. The tower may be either trayed or packed and is supplied with heat from a steam-heated reboiler. The overhead vapors, a mixture of $SO_2$ and steam, go through a partial condenser to reduce the water content. The water is returned to the top of the regenerator column as reflux. The $SO_2$ is compressed as required for transfer to the by-product processing unit.

5. Absorbent Purification - Any strong acids in the gas feed which reach the scrubber will react with the absorbent to form heat stable salts, i.e. salts which do not regenerate under the conditions in the regenerator. The level of heat stable salts in the circulating absorbent is controlled by taking a slipstream of less than 1% of lean absorbent into the purification unit where the amine salt absorbent is purified and returned to process.

6. By-Product Processing - The $SO_2$ from the regenerator contains water vapor, which is removed in the by-product processing unit using commercially available drying processes. If desired, the dry $SO_2$ can be liquified or further processed into sulfuric acid or sulfur, using conventional technology.

7. Waste Treatment Unit - The aqueous effluents from the prescrubber, and absorbent purification unit, comprising salts, acids, and particulates, are treated as required by conventional water treatment technologies. The volume of waste is only about 1% of that produced by conventional $SO_2$-removal technologies.

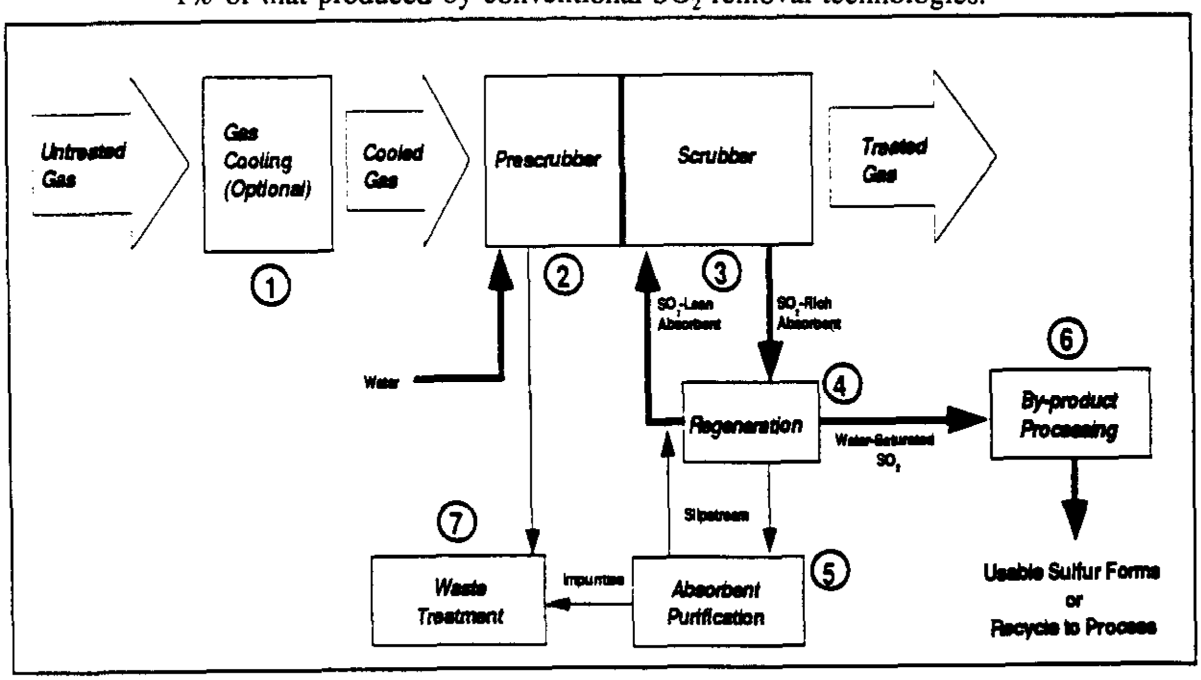


**Figure 1.**

## Pilot Plant Experience

The CANSOLV™ System was tested, at a 2 MWe pilot plant scale, during a 9-month period from February to November, 1991. The facility was located at the Suncor Oil Sands Group facility in Ft. Murray, Alberta.

The pilot plant was designed to treat, after the electrostatic precipitators, 10,000 $m^3/h$ (6000 ACFM) of flue gas emanating from the Suncor utilities boilers, which burn 7% sulfur petroleum coke as fuel. Three 70 MWe boilers fire 2,300 tons per day of petroleum coke that is produced on site by the bitumen upgrading process. Average flue gas conditions are given in Table I. The volume of flue gas treated in the pilot plant is about 3% of one boiler's output, roughly equivalent to about 2 MWe.

| | |
|---|---|
| Composition: | |
| $N_2$ | 81% |
| $CO_2$ | 11% |
| $O_2$ | 8% |
| $SO_2$ | 3600 ppm |
| $NO_x$ | 175 - 375 ppm |
| Cl, F | Present |
| Particulate | 0.07 - 0.14 $g/Nm^3$ (0.03 - 0.06 gr/SCF) |
| Temperature | 245° - 290° C (475° - 550°F) |
| Pressure | -0.25 kPa (-1" WC) |

**Table I. Average Flue Gas Conditions**

The critical elements of the CANSOLV System were demonstrated at the pilot plant scale:

1. **$SO_2$ Absorption** - up to 99% $SO_2$ removal at L/G ratios of less than 0.15 $l/m^3$ (1 USG/MACF) were demonstrated.

2. **Regeneration** - Stripping of $SO_2$ from rich absorbent has been achieved with a multi-trayed regenerator column.

3. **Absorbent Purification** - Heat stable salt removal from the CANSOLV Absorbent has been accomplished with very low amine salt loss.

4. **Process Stability** - The CANSOLV™ System chemistry results in a forgiving process, i.e robust, stable and easy to operate.

5. **Stability of UCARSOL® LH Absorbent** - The CANSOLV System absorbent is stable and does not deteriorate, nor lose its $SO_2$ absorbtion properties over time.

The results of the pilot plant program were promising, but it was recognized that a commercial-scale demonstration was needed to prove to the market that the CANSOLV System represented a viable technology for $SO_2$ removal. The proposed Clean Coal Technology project at Alcoa's Warwick plant will fulfill this need.

## CANSOLV™ SYSTEM CLEAN COAL TECHNOLOGY DEMONSTRATION

The Clean Coal Technology demonstration will be located at the Warrick Power Plant operated by the Alcoa Generating Corporation (AGC), a wholly owned subsidiary of the Aluminum Company of America Inc. (Alcoa). The Warrick Power Plant consists of three 144 MWe units wholly owned by AGC, and a fourth 300 MWe unit jointly owned by AGC and the Southern Indiana Gas & Electric Company (SIGECO). The facility is located in southern Indiana, adjacent to the Ohio River. It is over 30 years old and burns a high-sulfur Indiana coal. The typical composition of the coal and flue gas are shown in Table II.

| Coal Ultimate Analysis, Wt % | | Flue Gas Composition Vol % or ppmV | |
|---|---|---|---|
| Moisture | 12.92 | Oxygen | 5.28 |
| Carbon | 62.02 | Carbon Dioxide | 11.92 |
| Hydrogen | 4.58 | Nitrogen | 73.64 |
| Nitrogen | 1.22 | Water | 8.88 |
| Chlorine | 0.05 | Nitrogen Oxide (NOx) (ppmv) | 342 |
| Sulfur | 3.39 | Hydrogen Chloride (ppmv) | 33 |
| Ash | 8.23 | Sulfur Dioxide (ppmv) | 2,426 |
| Oxygen | 7.60 | Sulfur Trioxide (ppmv) | 27 |
| TOTAL | 100.00 | TOTAL | 100.00 |
| HHV, (kJ/kg) | 26,300 | Flue Gas Flow ($m^3/h$) | 488,000 |
| (Btu/lb) | 11,307 | (ACFM) | 287,000 |

**Table II.**

The CANSOLV™ System 75 MWe demonstration retrofit consists of two process areas: the in-duct Prescrubber and $SO_2$ Scrubber Units area, and the $SO_2$ Stripping, Amine Purification and $SO_2$ Drying/Liquefaction Units area.

The in-duct Prescrubber and $SO_2$ Scrubber will be housed in a new duct parallel to the existing duct. A new ID booster fan will be installed at grade to overcome the 15 - 25 mmHg (8 - 13" WC) pressure drop through the new duct. The existing duct will remain open to the chimney and booster fan, as a safeguard against implosion.

The $SO_2$ Stripping, Amine Purification, and $SO_2$ Drying/Liquefaction Units are located on a concrete pad about 15 meters (50 feet) south of the duct and roadway. The two areas are required to be separated to maintain the present roadway, operations access, and future crane positioning. This is easily accomplished using the CANSOLV System because the volumes of liquid moving between the two areas are easily handled. The ability to locate these units separately from the in-duct scrubbers is one of the advantages of the CANSOLV System for limited-space retrofit applications.

The existing chimney selected for discharge of the flue gas stream from the Scrubber Section is the No. 2 chimney. During the demonstration program, both Unit No. 3 and half of Unit No. 2 will discharge into the chimney. The Unit No. 2 discharge will be about 60°C (140°F) after being routed through the Scrubber Section. This will cause some local cold and wet areas within the chimney due to mixing with the high-sulfur flue gas from Unit No. 3. To reduce deterioration of the existing chimney, a borosilicate brick liner will be installed. To prevent corrosion, the existing duct will also be lined with borosilicate between the point of re-entry of the new duct and the chimney. The chimney and duct linings will be installed during a scheduled shutdown of the unit.

**Area Required**

The CANSOLV System requires a relatively small yard area, approximately 26 m x 14 m (86 ft x 46 ft), or 368 $m^2$ (3,956 $ft^2$). At the Warrick site, a comparable conventional limestone scrubber system process area would total 3,386 $m^2$ (36,450 $ft^2$). This is almost **ten times** the area required by the CANSOLV™ System.

**Results Expected**

Operation of the demonstration plant is scheduled to commence in mid-1995. Figure 2 shows those flows which will be monitored during the demonstration to prove the effectiveness of the CANSOLV System. It is expected to remove 98% of the $SO_2$ contained in the 75 MWe flue gas entering the CANSOLV System, reducing the $SO_2$ emissions from 17,700 tons/year to 354 tons/year. Tests will be conducted to demonstrate removal rates up to 99%.

| Inputs | | CANSOLV™ SYSTEM | Outputs |
|---|---|---|---|
| Untreated Flue Gas | → | | |
| Amine | → | | → Treated Flue Gas |
| Demineralized Water | → | | → Liquid $SO_2$ |
| Water | → | | → Sulfuric Acid 75% |
| Steam | → | | → Water Blowdown to Ash Pond |
| Sulfuric Acid 98% | → | | |
| Caustic | → | | |

**Figure 2. CANSOLV™ System Input/Output Flows**

Table III illustrates the change in air emission expected. It should be noted that, in addition to reducing $SO_2$ emission by 98%, the CANSOLV System also reduces emissions of particulate matter, $SO_3$, and HCl.

| Pollutant | Units | Current Emissions | Projected Emissions* |
|---|---|---|---|
| $SO_2$ | lbs/MMBtu<br>tons/year | 5.92<br>17,700 | 0.12<br>354 |
| Particulate Matter | lbs/MMBtu<br>tons/year | 0.12<br>352 | 0.03<br>88 |
| $SO_3$ | lbs/MMBtu<br>tons/year | 0.08<br>252 | 0.04<br>126 |
| HCl | lbs/MMBtu<br>tons/year | 0.053<br>160 | 0.003<br>8 |

* Difficult to project from the pilot plant results (treating petroleum-coke flue gas), but high removal rates are expected.

**Table III. Reduction in Air Emissions**

## PROCESS ECONOMICS

Union Carbide commissioned a study by an independent engineering firm to compare the economics of several commercial processes to the CANSOLV™ System for a site-specific case. Four lime/limestone processes and one regenerable process were selected for comparison. The power plant chosen as the basis of the study consisted of 2 x 150 MWe units. The FGD capital costs were based on coal containing 4.1% sulfur, while the operating costs were generated on the assumption that 3.3% sulfur coal was normally used. The results, shown in Figure 3, demonstrate that the CANSOLV System has significant economic advantages over existing technologies.

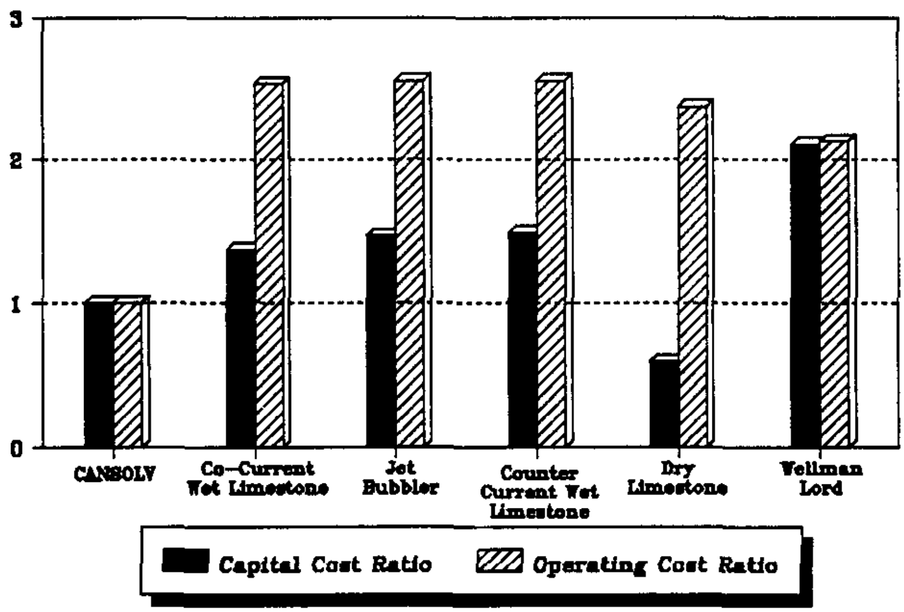


**Figure 3. Captial and Operating Costs, CANSOLV™ vs Other FGD Technologies**

## CONCLUSIONS

The CANSOLV System for the removal of $SO_2$ from gas streams has been demonstrated at a pilot plant size of 2 MWe. Removal rates up to 99% can consistently be achieved by appropriate changes in the system operating parameters. The absorbent is highly stable and is capable of effecting high removal rates at high gas velocities and low L/G ratios. The result is a process which requires a comparably small footprint and consequently is ideal for retrofit situations.

In addition, projected economics are extremely favorable: projected capital costs are 30% lower than commercial wet limestone systems, and projected operating costs are 60% lower. This significant improvement in costs should result in the CANSOLV™ System's becoming the preferred $SO_2$ removal technology in the latter half of the decade.

The DOE Clean Coal Technology demonstration project at Alcoa's Warrick Plant will be *instrumental in proving the commercial viability of the CANSOLV System.*

## REFERENCES


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3. "Gas Purification" A. L. Kohl and F. C. Riesenfeld, 4th Edition, Gulf Publishing.

4. "Fundamental Chemistry of Sulfur Dioxide Removal and Subsequent Recovery via Aqueous Scrubbing", M. Schmidt, Int. J. Sulfur Chem., Part B, Vol. 7, Number 1 pp. 11-19.

# APPENDIX A

# AGENDA

# U.S. DEPARTMENT OF ENERGY

# FIRST ANNUAL
# CLEAN COAL TECHNOLOGY CONFERENCE

## AGENDA

**TUESDAY EVENING (SEPTEMBER 22, 1992)**

RECEPTION COCKTAIL PARTY (Sponsored by **Centerior Energy**)

**WEDNESDAY MORNING (SEPTEMBER 23, 1992)**

PLENARY SESSION

Moderator: **Jack S. Siegel**, Deputy Assistant Secretary, Coal Technology, U.S. Department of Energy

Opening Greeting: **Donald E. Jakeway**, Director, Ohio Department of Development

State Regulatory View of Compliance Strategies: **The Honorable Craig A. Glazer**, Chairman, Public Utilities Commission of Ohio

Perspective of Utility Investing in a Major CCT Power Generating Technology: **Girard F. Anderson**, President and Chief Operating Officer, Tampa Electric Company

Perspective of Utility Investing in a Major CCT Retrofit Technology: **Gary L. Neale**, President and Chief Operating Officer, Northern Indiana Public Service Company

STATE REGULATORY PANEL SESSION

Moderator: **The Honorable Ashley C. Brown**, Commissioner, Public Utilities Commission of Ohio

Panel Members:

**The Honorable Daniel Wm. Fessler**, President, California Public Utilities Commission

**The Honorable Karl A. McDermott**, Commissioner, Illinois Commerce Commission

**The Honorable James R. Monk**, Chairman, Indiana Utility Regulatory Commission

**The Honorable Bil Tucker, Ph.D.**, Chairman, Wyoming Public Service Commission

**WEDNESDAY AFTERNOON (SEPTEMBER 23, 1992)**

LUNCHEON KEYNOTE SPEAKER:
Clean Coal Technology: Energy to Drive World Evolution
**Thomas Altmeyer**, Senior Vice President, Government Affairs, National Coal Association.

CONCURRENT TECHNICAL SESSIONS

SESSION 1: Advanced Power Generation Systems
*Chairs: Larry K. Carpenter, DOE METC*
*Dr. Larry M. Joseph, DOE Headquarters*

**American Electric Power Pressurized Fluidized Bed Combustion Technology Update**, Mario Marrocco, Group Manager, PFBC, American Electric Power Service Corporation. Co-author: D. R. Hafer, American Electric Power Service Corporation.

**Nucla CFB Demonstration CCT Program Summary: Project Origins through Test Completion,** Stuart A. Bush, Senior Engineer, Project Coordinator, Tri-State Generation and Transmission Association, Inc. Co-authors: M.A. Friedman, Senior Associate, Combustion Systems, Inc., N. F. Rekos, U.S. DOE Morgantown Energy Technology Center, and T. J. Heller, Tri-State Generation and Transmission Association, Inc.

**Status of the Piñon Pine IGCC Project**, John W. Motter, Advanced Generation Projects Manager, Sierra Pacific Power Company

**DMEC-1 Pressurized Circulating Fluidized Bed Demonstration Project**, Gary E. Kruempel, Manager, Generation Engineering, Midwest Power.
Co-authors: S.J. Ambrose, Midwest Power, and S.J. Proval, Pyropower Corporation

**The Wabash River Coal Gasification Repowering Project**, David G. Sundstrom, Business Development Manager—Coal Gasification, Destec Energy, Inc.

**Status of Tampa Electric Company IGCC Project**, Stephen D. Jenkins, Manager, Advanced Technology, TECO Power Services

SESSION 2: High Performance Pollution Control Systems
*Chairs: Dr. Joseph P. Strakey, DOE PETC*
*Dr. Lawrence Saroff, DOE Headquarters*

**Acid Rain Compliance — Advanced Co-Current Wet FGD Design for the Bailly Station,** Robert C. Reighard, Director of Operations, Pure Air. Authors: Beth Wrobel, Northern Indiana Public Service Company, and Don C. Vymazal, Pure Air

**Demonstration of Innovative Applications of Technology for the CT-121 FGD Process,** David P. Burford, Project Manager, Southern Company Services, Inc. Co-authors: Harry J. Ritz, DOE Pittsburgh Energy Technology Center, and Oliver W. Hargrove, Radian Corporation.

**$NO_x/SO_2$ Removal With No Waste — The SNOX Process**, Timothy D. Cassell, SNOX Site Leader, ABB Environmental Systems. Co-authors: Sher M. Durrani, Project Manager, Ohio Edison Company, and Robert J. Evans, Project Manager, U.S. DOE Pittsburgh Energy Technology Center.

**SNRB - $SO_2$, $NO_x$, and Particulate Emissions Control with High Temperature Baghouse**, Kevin E. Redinger, Project Manager, The Babcock & Wilcox Company. Co-authors: Rita E. Bolli, Ohio Edison Company, Ronald W. Corbett, U.S. DOE Pittsburgh Energy Technology Center, and Howard J. Johnson, Ohio Coal Development Office.

**The NOXSO Clean Coal Technology Project: A 115 MW Demonstration Unit,** Dr. James B. Black, Sr. Project Engineer, NOXSO Corporation. Co-authors: L.G. Neal, John L. Haslbeck, and Mark C. Woods, NOXSO Corporation

SESSION 2 (continued):

**Overview of the Milliken Station Clean Coal Demonstration Project,**
Mark E. Mahlmeister, Project Engineer, New York State Electric & Gas Corporation. Co-authors: J.E. Hofman, NALCO Fuel Tech, R.M. Statnick, CONSOL, Inc., C.E. Jackson, Gilbert Commonwealth, Gerard G. Elia, U.S. DOE Pittsburgh Energy Technology Center, J. Glamser, S-H-U/Natec, and R.E. Aliasso, Stebbins Engineering & Manufacturing Co.

GOVERNMENT EXPORT PANEL SESSION

Moderator: **Peter J. Cover**, Program Manager, Coal Technology Exports, Office of Planning and Environment, U.S. Department of Energy's Office of Fossil Energy.

Panel Members:
**Dr. Robert A. Siegel**, Chief, Economic & Policy Analysis Division, Policy Directorate, U.S. Agency for International Development
**Dr. Joseph J. Yancik**, Director, Office of Energy, U.S. Department of Commerce/ International Trade Administration
**John W. Wisniewski**, Vice President, Engineering, Export-Import Bank of the U.S.
**Jack Williamson**, U.S. Trade and Development Program
**Harvey A. Himberg**, Director for Development Policy and Environmental Affairs, Overseas Private Investment Corporation.

INDUSTRY EXPORT PANEL SESSION

Moderator: **Ben N. Yamagata**, Executive Director, Clean Coal Technology Coalition

Panel Members:
**Anthony F. Armor**, Director, Fossil Power Plants Department, Electric Power Research Institute
**Robert D. McFarren**, Vice President, Stone and Webster International Corporation
**Dr. Charles J. Johnson**, Head Coal Project, East-West Center

## THURSDAY MORNING (SEPTEMBER 24, 1992)

OPENING REMARKS—Role of Clean Coal Technologies in the International Marketplace:
**The Honorable James G. Randolph**, Assistant Secretary for Fossil Energy, U.S. Department of Energy

UTILITY PANEL DISCUSSIONS

Moderator: **Dr. George T. Preston**, Vice President, Generation and Storage Division, Electric Power Research Institute (EPRI)

Panel Members:
**Dr. James J. Markowsky**, Senior Vice President and Chief Engineer, American Electric Power Service Corporation
**Stephen C. Jenkins**, Senior Vice President, Commercial Development, Destec Energy, Inc.
**Randall E. Rush**, Director, Clean Air Act Compliance, Southern Company Services, Inc.
**George P. Green**, Manager, Electric Supply Resources, Public Service Company of Colorado
**Howard C. Couch**, Manager, Environmental and Special Projects Department, Ohio Edison Company

CONCURRENT TECHNICAL SESSIONS

SESSION 3: Advanced Power Generation Systems

*Chair: R. Daniel Brdar, DOE METC*

**York County Energy Partners DOE CCI ACFB Demonstration Project,** Dr. Shoou-I Wang, General Manager, EES Technology, Air Products and Chemicals, Inc. Co-authors: J. Cox and D. Parham, Foster Wheeler Energy Corporation

**Coal Gasification — An Environmentally Acceptable Coal-Burning Technology for Electric Power Generation**, Lawrence J. Peletz, Jr., Consulting Engineer, ABB Combustion Engineering, Inc. Co-authors: Herbert E. Andrus, Jr., and Paul R. Thibeault, ABB Combustion Engineering, Inc.

**Toms Creek IGCC Demonstration Project**, Gordon A. Chirdon, Director of Engineering and Technology, Coastal Power Production Company. Co-authors: J.G. Patel, Vice President, New Technology, R. T. Silvonen, Tampella Power Corporation, and M. J. Hobson, Coastal Power Production Company.

SESSION 4: $NO_x$ Control Systems

*Chair: Arthur L. Baldwin, DOE PETC*

**500 MW Wall-Fired Low $NO_x$ Burner Demonstration**, John N. Sorge, Process Engineer, Southern Company Services, Inc. Co-author: Arthur L. Baldwin, Program Coordinator, $NO_x$ Control Technology, U.S. DOE Pittsburgh Energy Technology Center

**180 MW Tangentially-Fired Low $NO_x$ Burner Demonstration**, Robert R. Hardman, Research Engineer, Southern Company Services, Inc. Co-author: Gerard G. Elia, U.S. DOE Pittsburgh Energy Technology Center

**Demonstration of Selective Catalytic Reduction (SCR) Technology for the Control of Nitrogen Oxide ($NO_x$) Emissions from High-Sulfur, Coal-Fired Boilers**, J. Douglas Maxwell, SCR Project Manager and Principal Research Engineer, Southern Company Services, Inc. Co-author: Arthur L. Baldwin, Program Coordinator, $NO_x$ Control Technology, U.S. DOE Pittsburgh Energy Technology Center

SESSION 5: Coal Processing Systems

*Chair: Douglas M. Jewell, DOE METC*

**Design, Construction, and Start-up of ENCOAL Mild Coal Gasification Project,** James P. Frederick, Project Manager, ENCOAL Corporation

**Rosebud SYNCOAL™ Partnership Advanced Coal Conversion Process Demonstration Project,** Ray W. Sheldon, Director of Engineering, Western SynCoal Company. Co-authors: A. J. Viall, Western Energy Company, and J. M. Richards, Scoria, Inc.

**Fuel and Power Coproduction—The Integrated Gasification/Liquid Phase Methanol (LPMEOH™ ) Demonstration Project**, William R. Brown, Manager, Syngas Conversion Systems, Air Products and Chemicals, Inc. Co-author: Frank S. Frenduto, Air Products and Chemicals, Inc.

**THURSDAY AFTERNOON (SEPTEMBER 24, 1992)**

LUNCHEON KEYNOTE SPEAKER:

The Clean Air Marketplace—The Clean Air Act: Spurring Innovation, Jobs, and Exports

**Robert D. Brenner**, Director, Air Policy Office, U.S. EnvironmentalProtection Agency

CONCURRENT TECHNICAL SESSIONS

SESSION 6: Advanced Combustion/Coal Processing

*Chairs: Dennis N. Smith, DOE PETC*
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**An Air Cooled Slagging Combustor with Internal Sulfur, Nitrogen, and Ash Control for Coal and High Ash Fuels**, Dr. Bert Zauderer, President, Coal Tech Corporation. Co-authors: E.S. Fleming and B. Borok, Coal Tech Corporation.

**The Healy Clean Coal Project**, Steve M. Rosendahl, Project Manager, Stone & Webster Engineering Corporation, and Dennis V. McCrohan, Alaska Industrial Development and Export Authority

**Demonstration of PulseEnhanced™ Steam Reforming in an Application for Gasification of Coal**, Richard E. Kazares, Vice President, Sales and Applications Engineering. Co-authors: William G. Steedman, Senior Systems Engineer, ThermoChem, Inc., and Dr. Momtaz N. Mansour, President, MTCI, Inc.

**Coal Quality Expert: Status and Software Specifications**, Clark D. Harrison, President, CQ, Inc.

**Self Scrubbing Coal: An Integrated Approach to Clean Air**, Robin L. Godfrey, Executive Vice President, Custom Coals Corporation

SESSION 7: $NO_x$ Control Systems

*Chairs: Richard R. Santore, DOE PETC*
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**Full Scale Demonstration of Low $NO_x$ Cell™ Burners at Dayton Power & Light's J.M. Stuart Station Unit No. 4**, Roger J. Kleisley, Contract Manager, The Babcock & Wilcox Company, David A. Moore, Engineering Supervisor, Dayton Power & Light. Co-authors: C.E. Latham and T.A. Laursen, The Babcock & Wilcox Company, and C.P. Bellanca and H.V. Duong, Dayton Power & Light·

**Demonstration of Coal Reburning for Cyclone Boiler $NO_x$ Control — A DOE Clean Coal II Project**, Anthony S. Yagiela, Cyclone Reburn Project Manager, The Babcock & Wilcox Company. Co-authors: G.J. Maringo, Combustion Systems Development Engineer, The Babcock & Wilcox Company, R.J. Newell, Supervisor, Plant Performance, Wisconsin Power & Light, and H. Farzan, Senior Research Engineer, The Babcock & Wilcox Company

**Gas Reburning for Combined $NO_x$ and $SO_2$ Emissions Control in Utility Boilers**, Leonard C. Angello, Director, Utility Systems, Energy and Environmental Research Corporation. Co-authors: D. A. Engelhardt, B.A. Folsom, J. C. Opatrny, T.M. Sommer, Energy and Environmental Research Corporation, and H.J. Ritz, U.S. DOE Pittsburgh Energy Technology Center

**Integrating Gas Reburning with Low $NO_x$ Burners**, Todd M. Sommer, Vice President, Energy and Environmental Research Corporation. Co-authors: C.C. Hong, H. M. Moser, Energy and Environmental Research Corporation, H. J. Ritz, U.S. DOE Pittsburgh Energy Technology Center

**Micronized Coal Reburning for $NO_x$ Control on a 175 MWe Unit**, Dale T. Bradshaw, Manager, Resource Development Department, Tennessee Valley Authority. Co-authors: Thomas F. Butler, Tennessee Valley Authority, William K. Ogilvie, MicroFuel Corporation, Ted Rosiak, Jr., Duke/Fluor Daniel, and Robert E. Sommerlad, Research-Cottrell Companies

**Integrated Dry $NO_x$/$SO_2$ Emissions Control System Update**, Terry Hunt, Professional Engineer, Public Service Company of Colorado. Co-author: John B. Doyle, The Babcock & Wilcox Company

SESSION 8: Retrofit for $SO_2$ Control

*Chairs: Dr. John A. Ruether, DOE PETC*

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**Update and Results of Bechtel's Confined Zone Dispersion (CZD) Process Demonstration at Pennsylvania Electric Company's Seward Station**, Jack Z. Abrams, Principal Engineer, Bechtel Group, Inc. Co-authors: Allen G. Rubin, Project Manager Bechtel Corporation, and Arthur L. Baldwin, Program Coordinator, $NO_x$ Control Technology, U.S. DOE Pittsburgh Energy Technology Center

**LIFAC Sorbent Injection for Flue Gas Desulfurization**, James Hervol, Project Manager, ICF Kaiser Engineers, Inc. Co-authors: Richard Easler and Judah Rose, ICF Kaiser Engineers, Inc., and Juhani Viiala, Tampella Power Corporation.

**The Clean Coal Technology Program: 10 MWe Demonstration of Gas Suspension Absorption for Flue Gas Desulfurization**, Frank E. Hsu, Senior Manager of Special Projects, AirPol, Inc. Co-author: Sharon K. Marchant, U.S. DOE Pittsburgh Energy Technology Center

**Final Results of the DOE LIMB and Coolside Demonstration Projects**, Michael J. DePero, Contract Manager, The Babcock & Wilcox Company. Co-authors: Thomas R. Goots and Paul S. Nolan, The Babcock & Wilcox Company

**Recovery Scrubber Installation and Operation**, Dr. Garrett L. Morrison, Ph.D, President and CEO, Passamaquoddy Technology, L.P.

**Demonstration of the Union Carbide CANSOLV™ System Process at the ALCOA Generating Corporation Warrick Power Plant**, Alex B. Barnett, Business Manager, Power Generation, Union Carbide Chemicals and Plastics Company, Inc. Co-author: L.E. Hakka, Union Carbide Chemicals and Plastics Canada, Inc.

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